EXHIBIT LIST

IN THE MATTER OF:	)	
	)	
AMENDMENTS TO 35 ILL. ADM. CODE	)	R18-20
225.233, MULTI-POLLUTANT	)	(Rulemaking - Air)
STANDARDS (MPS)	)	

1. Prefiled testimony of Rory Davis on behalf of the Illinois Environmental Protection Agency (IEPA)

2. Prefiled questions for Rory Davis by the Environmental Groups

3. Prefiled questions for Rory Davis by Dynegy Midwest Generation *et al.*

4. Prefiled questions for Rory Davis by People of the State of Illinois (People)

5. Prefiled questions for Rory Davis by Illinois Pollution Control Board

6. Prefiled answers to all prefiled questions by IEPA

7. Letter dated February 24, 2017 to Ms. Yasmine Keppner-Bauman, Unit Manager IEPA Re: IPH, LLC

8. Letter dated February 24, 2017 to Ms. Yasmine Keppner-Bauman, Unit Manager IEPA Re: 2016 NOX and SO2 MPS Compliance Report

9. Prefiled testimony of James P. Gignac on behalf of the People

10. Excel Spread Sheet included as separate exhibit to Mr. Gignac's testimony

11. Prefiled questions for James P. Gignac by IEPA

12. Prefiled Answers to question by IEPA for James P. Gignac James P. Gignac James P. Gignac

13. Email from Douglas Aburano to David Bloomberg dated August 22, 2017

14. Prefiled testimony of Rick Diericx on behalf of Dynegy Midwest Generation *et al.*

15 Prefiled testimony of Dean Ellis on behalf of Dynegy Midwest Generation *et al.*

16. Prefiled answers by Dynegy Midwest Generation *et al.* to Board prefiled questions

17. Prefiled answers by Dynegy Midwest Generation *et al.* to IEPA prefiled questions

18. Answers by Dynegy Midwest Generation *et al.* to questions by the People

19. Prefiled questions for Rick Diericx and Dean Ellis by IEPA

20. Prefiled questions for Rick Diericx by the Environmental Groups

21. Prefiled questions for Dean Ellis by the Environmental Groups

22. Prefiled questions for Dynegy Midwest Generation *et al.* by the People

23. Prefiled questions for Dynegy Midwest Generation *et al.* by the Board

24. Dynegy's response to questions, filed February 16, 2018

25. Environmental Groups prefiled question for Dynegy, filed on March 2, 2018 (see electronic filing for attachments/exhibits to questions)

26. Attorney General's Office prefiled question for Dynegy, filed on March 2, 2018 (see electronic filing for attachments/exhibits to questions)

27. Attorney General's Office response to questions, filed February 16, 2018

28. Board's prefiled question for Dynegy, filed on March 2, 2018

29. IEPA response to questions, filed February 16, 2018

30. Attorney General's Office prefiled question for IEPA, filed on March 2, 2018 (see electronic filing for attachments/exhibits to questions)

31. Dynegy's prefiled question for IEPA, filed on March 2, 2018

32. Board's prefiled question for IEPA, filed on March 2, 2018

33. Group Exhibit from IEPA the "Five-Year Progress Report for Illinois Haze State Implementation Plan", and "Regional Haze State Implementation Plan For Illinois" May 10, 2011, and "Technical Support Document for Best Available Retrofit Technology Under the Regional Haze Rule" April 29, 2011, and 77 Fed. Reg. 3966-3975 (Jan. 26, 2012), and 77 Fed. Reg. 39943-39948 (July 6, 2012)

34. Prefiled testimony of Brian Urbaszewski on behalf of Environmental Groups, filed February 6, 2018 (see electronic filing for attachments/exhibits to testimony)

35. IEPA prefiled questions for Brian Urbaszewski, filed March 2, 2018

36. Dynegy's prefiled questions for Brian Urbaszewski, filed March 2, 2018

37. April 3, 2018, prefiled testimony of Andrew Armstrong on behalf of the People, with corrections.

38. April 10, 2018, prefiled questions for Andrew Armstrong, filed by IEPA

39. April 10, 2018, prefiled questions for Andrew Armstrong, filed by Dynegy

40. April 10, 2018, prefiled questions for Andrew Armstrong, filed by the Board

41. "Weak MISO prices compound Ill. Coal plant woes" Friday April 13, 2018

42. April 3, 2018, prefiled testimony of Tamara Dzubay on behalf of ELPC and Sierra Club.

43. Corrections to prefiled testimony of Tamara Dzubay.

44. April 10, 2018, prefiled questions for Tamara Dzubay, filed by Dynegy

45. April 10, 2018, prefiled questions for Tamara Dzubay, filed by the Board

46. April 10, 2018, prefiled questions for IEPA, filed by Dynegy

47. Email and Attachment from Douglas Aburano with USEPA and David Bloomberg with IEPA, dated April 12, 2018

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

The Illinois Attorney General's Office, on behalf of the People of the State of Illinois ("People"), hereby files the pre-filed testimony of Assistant Attorney General Andrew Armstrong, as provided by the Hearing Office Order issued on March 14, 2018.

I. INTRODUCTION

During the March 7, 2018 hearing, witnesses for the People were asked by counsel for Dynegy Midwest Generation, LLC, Illinois Power Generating Company, Illinois Power Resources Generating, LLC and Electric Energy, Inc. (collectively, "Dynegy") whether the Illinois Attorney General would support Illinois EPA's proposed annual mass-based emission caps for sulfur dioxide ("SO_2") and nitrogen dioxide ("NOx"), should the Illinois Pollution Control Board ("Board") move forward with the Illinois Environmental Protection Agency's ("Illinois EPA") October 2, 2017 proposal to amend the Multi-Pollutant Standards ("MPS"). *See*, *e.g.*, March 7, 2018 R18-20 Hearing Transcript at 41, line 24, to 42, line 4. We do not support the Illinois EPA's proposed SO_2 annual emission cap of 49,000 tons nor the NOx annual emission cap of 25,000 tons.

This testimony, first and foremost, restates the position in the People's Pre-Filed Testimony filed December 11, 2017: the Board should reject the Illinois EPA's proposed amendments and this rulemaking. Illinois EPA's proposal would have a negative environmental impact. By removing annual fleet-wide emission rate limits for SO_2, the proposed amendments

Exhibit 37
R18-20
4/19/2018
MT

CERTIFICATE OF SERVICE

I, STEPHEN J. SYLVESTER, an attorney, do certify that on April 3, 2018, I caused the Pre-Filed Testimony of Andrew Armstrong on behalf of the Illinois Attorney General's Office and the Notice of Filing to be served upon the persons listed in the attached Service List by email for those who have consented to email service and by U.S. Mail for all others.

/s/ Stephen J. Sylvester
STEPHEN J. SYLVESTER

would authorize prospective new owner Vistra Energy Corporation to close down up to four power plants that are relatively well-controlled for SO_2—Baldwin, Coffeen, Duck Creek, and Havana—and increase the utilization of higher-polluting plants. *See*, *e.g.*, March 6, 2018 R18-20 Hearing Transcript at 140, line 1, to 141, line 16 (Illinois EPA's witness agreeing that its proposed amendments would newly allow Vistra or Dynegy to close down controlled plants while continuing to operate higher-polluting plants).

Moreover, Illinois EPA's proposed annual mass-based emission caps would immediately permit SO_2 and NOx pollution from the current MPS units to significantly increase in excess of actual emissions under the current MPS. Below, we offer an analysis of actual emissions under the current MPS, using actual historical heat inputs and unit-level emission rates. This analysis demonstrates that Illinois EPA's proposed caps of 49,000 tons of SO_2 and 25,000 tons of NOx far exceed the current MPS units' actual emissions of both pollutants for each of the past five years, from 2013 through 2017.

Moreover, even if the MPS units in the future could otherwise reach peak historical heat inputs, the current MPS would limit actual emissions of both SO_2 and NOx to amounts well below levels that would be permitted by Illinois EPA's proposed caps. This outcome becomes particularly clear when the MPS's requirement of averaging unit-level emission rates across the MPS groups is taken into account. In a nutshell: under the current MPS, Dynegy cannot operate its higher-polluting uncontrolled units as intensively as it did before, relative to controlled units, because the fleet as a whole could not meet now applicable MPS emission rate limits. Applying 2017 unit-level emission rates and the same 2002 actual unit-level heat inputs earlier relied upon by Illinois EPA to show compliance with the Regional Haze Rule, we have projected actual annual emissions of no more than **34,094 tons of SO_2 and 18,920 tons of NOx** under the current MPS. *See* Attachment 9. Any annual emission caps that exceed those levels would certainly permit greater emissions from the MPS fleet than would be expected under the current MPS—particularly if such caps are not reduced upon the retirement or mothballing of MPS units.

To be clear: the People do not propose any new rules, or amendments thereto, but rather that the Board reject Illinois EPA's proposal for its failure to provide any environmental benefit. *See In the Matter of Amendments to 35 Ill. Adm. Code 225, Control of Emissions from Large Combustion Sources (Mercury Monitoring)*, R09-10 (Apr. 16, 2009) at 29 (adopting amendments to the MPS where they offered a "net environmental benefit"). If the Board does proceed with this rulemaking, though, the People suggest that the Board significantly revise Illinois EPA's proposed annual mass-based emission caps downward, at least to 34,094 tons for SO_2 and 18,920 tons for NOx, and to require that such caps be reduced upon the retirement or mothballing of MPS units. *See* 35 Ill. Adm. Code 102.600(a).[1]

In addition to responding to Dynegy's question presented at the March 7, 2018 hearing, this testimony also states support for the concept advanced by Board Member Zalewski during the January 18, 2017 hearing of "layering" one or more emission rate limits over mass-based emission caps. January 17, 2018 R18-20 Hearing Transcript at 30, lines 19-23. Bolstering Illinois EPA's proposed mass-based emission caps with emission rate limits would help ensure that the MPS fleet continues utilizing all current pollution controls—including an SO_2 control device at Newton Unit 1 that apparently was in operation during 2017, but not to this

---

1 Section 102.600(a) of the Board's Procedural Rules, 35 Ill. Adm. Code 102.600(a), provides as follows:

> The Board may revise the proposed regulations before adoption upon its own motion or in response to suggestions made at hearing and in written comments made prior to second notice. No additional hearings on the revisions need be held.

point disclosed[2] to the Board.[3] The People at this time are not proposing any specific emission rates for the Board to consider and adopt, as our position has consistently been that the Board should reject the proposal. However, we have provided, for the Board's consideration, unit-level emission rates for each current MPS unit for the past five years, from 2013 through 2017. *See* IAGO Pre-Filed Testimony (Dec. 11, 2017) (2016), Ex. 1; Attachments 3-6 hereto (2013-2015 and 2017). This historical data demonstrates that the MPS units' emission rates are in fact consistent from year to year. Accordingly, in our view, Board Member Zalewski's proposal has merit and should be further considered by the Board, if it determines that the MPS should be revised at all.[4]

II. THE BOARD SHOULD CONSIDER THE IMPACT ILLINOIS EPA'S AMENDMENTS WOULD HAVE ON ACTUAL EMISSIONS.

Illinois EPA in this proceeding has advanced two notable premises in support of its proposed emission caps: (1) that it is required under Section 110(l) of the Clean Air Act, 42 U.S.C. § 7410(l), to compare the emissions that would be "allowable" under its proposed amendments, to those that would be "allowable" under the MPS as it currently stands; and (2) that it would be "problematic" to compare "actual" emissions under the current MPS to projected

---

2 The Board specifically asked Illinois EPA to "[p]rovide a table listing each facility and unit along with the current pollution control equipment." IEPA January 12, 2018 Responses to Pre-Filed Questions at 7, Ques.10.

3 *See* Attachments 9 and 10 (May 24, 2016 construction permit and June 9, 2017 revised construction permit for SO_2 control equipment issued by Illinois EPA to Dynegy).

4 In our December 11, 2017 Pre-Filed Testimony, we also suggested the Board might consider combining the two existing MPS Groups into a single group, under new emission rates. The Board in its Pre-filed Questions to Illinois EPA sought the Agency's position on this issue. Illinois EPA rejected this approach claiming that it would not provide the "operational flexibility" Dynegy sought. IEPA January 12, 2018 Responses to Pre-Filed Questions at 2-3, Ques. 1.b. At this point, since there has been no further interest expressed in that concept, we do not provide any additional suggestions to the Board along those lines.

"actual" emissions if the MPS amendments were adopted. *See*, *generally*, IEPA Technical Support Document at 8-12.

Both premises are faulty. First, as discussed in this section of our testimony, there is no requirement under the Clean Air Act that Illinois EPA or the Board consider only an "allowable-to-allowable" comparison in evaluating Illinois EPA's proposed amendments. Rather, the United States Environmental Protection Agency ("USEPA") has consistently taken the position that an "anti-backsliding" analysis under Section 110(l) requires consideration of a proposed SIP amendment's impact on "actual," not allowable, emissions. Second, as discussed below, the actual emissions from the MPS fleet for the past three years have been significantly below the caps proposed by Illinois EPA and, moreover, would remain so under the current MPS even if the fleet were otherwise capable of increasing heat inputs to historical peaks.

As an initial point, the Board's decision of whether to move forward with Illinois EPA's proposed amendments is not in any case constrained to an analysis under Section 110(l). When the Board previously adopted amendments to the MPS in 2009, it did so because it found the amendments offered a "net environmental benefit," based on an analysis of projected actual—not allowable—emissions. *In the Matter of Amendments to 35 Ill. Adm. Code 225, Control of Emissions from Large Combustion Sources (Mercury Monitoring)*, R09-10 (Apr. 16, 2009) at 16, 29. The Board made the same finding when it granted variances from the MPS in 2012 and 2013. *Ameren Energy Resources v. IEPA*, PCB 12-126 (Sept. 20, 2012); *Illinois Power Holdings, LLC v. IEPA*, PCB 14-10 (Nov. 21, 2013) at 37. There is no reason for the Board to impose a lesser standard in assessing the amendments Illinois EPA now proposes.

Moreover, though, Illinois EPA's interpretation of Section 110(l) of the Clean Air Act is inconsistent with USEPA's. Illinois EPA asserts that "the methodology used by the Agency to calculate **allowable** emissions was chosen because it is the method the State is required to use to demonstrate that this SIP revision is approvable by USEPA." IEPA Responses and Information Requested from the January Hearings (Feb. 16, 2018), at 2 n.1 (emphasis added). USEPA, though, has long taken the position that the appropriate inquiry when conducting an "anti-backsliding" analysis pursuant to Section 110(l) is whether "**actual**" emissions, not allowable emissions, will increase. *See, e.g., Kentucky Resources Council, Inc. v. EPA*, 467 F.3d 986, 995 (6th Cir. 2006) ("As long as **actual** emissions in the air are not increased, EPA believes that equivalent (or greater) emissions reductions will be acceptable to demonstrate non-interference.") (quoting 70 Fed. Reg. 28429, 28430 (May 15, 2005)) (emphasis added); USEPA, *Approval and Revision of Air Plans; Arizona; Regional Haze State and Federal Implementation Plans; Reconsideration*, 83 Fed. Reg. 15139, 15149 (Mar. 27, 2017) (cited by Dynegy to Illinois EPA on page 3 of memorandum attached as Attachment 9 to IEPA Responses to Pre-Filed Questions (Jan. 12, 2018)).

The difference between "allowable" and "actual" emissions can be seen by comparing Sections 203.104 and 203.107 of the Board's Air Pollution Regulations, 35 Ill. Adm. Code 203.104 and 203.107, pertaining to construction and modification of major sources. In this proceeding, Illinois EPA has provided the following definition of "allowable emissions": "Allowable emissions simply means the amount of a given pollutant that a unit source, or in this case, a group of sources, is allowed by rule, law, or permit to emit." January 17, 2018 R18-20 Hearing Transcript at 22, lines 5-8. This definition reflects the definition of "allowable emissions" provided in 35 Ill. Adm. Code 203.107.[5] By contrast, 35 Ill. Adm. Code 203.104

---

[5] 35 Ill. Adm. Code 203.107 provides the following definition:

provides the following definition for "actual emissions":

> "Actual Emissions" means the actual rate of annual emissions of a pollutant from an emissions unit as of a particular date. Actual emissions are equal to the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during the two-year period which immediately precedes the particular date or such other period which is determined by the Illinois Environmental Protection Agency (Agency) to be representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored or combusted during the selected time period; however:
>
> a) The Agency shall allow the use of a different time period upon a demonstration by the applicant to the Agency that the time period is more representative of normal source operation. Such demonstration may include, but need not be limited to, operating records or other documentation of events or circumstances indicating that the preceding two years is not representative of normal source operations . . . .

A key difference, then, between "allowable emissions" and "actual emissions" is that "actual emissions" reflect actual historical "operating hours" and "production rates," as well as historical emission rates. *Id.* Considering actual emissions requires some analysis of how pollution sources operate in the real world, not just the maximum amount of pollution they

---

"Allowable emissions" means the emission rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable permit conditions or other such federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

1) Any applicable standards adopted by the United States Environmental Protection Agency (USEPA) pursuant to Sections 111 and 112 of the Clean Air Act (42 U.S.C. 7401, et seq.) and made applicable in Illinois pursuant to Section 9.1 of the Environmental Protection Act (Act) (Ill. Rev. Stat. 1991, ch. 111 1/2, pars. 1001 et seq.) [415 ILCS 5/1 et seq.];

2) The applicable emission standards or limitations contained in this Chapter and approved by USEPA pursuant to Section 110(a)(2) or 110 (a)(3) of the Clean Air Act, including those standards or limitations with a future compliance date and any other emission standard or limitation enforceable under the Environmental Protection Act or by the USEPA under Section 113 of the Clean Air Act; or

3) The emissions rate specified as a federally enforceable permit condition including those emissions rates with a future compliance date.

would legally be allowed to emit in a non-existent reality of maximum operation and emission rates.

Analyzing proposed amendments to a rule regulating specifically coal-fired power plants based solely on "allowable" emissions would paint a particularly distorted picture of those amendments' environmental impact. As USEPA maintained to the Seventh Circuit Court of Appeals in 2014, it was USEPA's "long-standing practice and EPA policy" to use actual emissions data for coal-fired power plants "when demonstrating permanent and enforceable emission reductions." *Sierra Club v. USEPA*, 774 F.3d 383, 396 (7th Cir. 2014) (quoting USEPA brief).[6] USEPA implemented this policy because "assuming that all sources would be operating at maximum capacity at once would result in a gross overestimation of levels." *Id.* The Seventh Circuit concurred with USEPA's approach: "[USEPA] has articulated a rational basis for its conclusion . . . that using maximum allowable emissions levels for power plants would have been unrealistic." *Id.* at 397.

Using maximum allowable emissions in this rulemaking as the sole basis for analyzing the proposal's environmental impact would be equally unrealistic and unreasonable. The Board instead should consider actual emissions and the beneficial impact that the MPS currently has, and reject the proposed amendments.

III. THE MPS FLEET'S ACTUAL EMISSIONS FOR THE PAST THREE YEARS HAVE BEEN WELL BELOW ILLINOIS EPA'S PROPOSED EMISSION CAPS.

Simply put: coal-fired power plants do not operate all of the time. In a chart attached to the Illinois Attorney General's Responses to Questions Raised During First Set of Hearings, the People provided capacity factors for current MPS units, from 2008 through 2017, calculated

---

[6] The court's decision related to USEPA's redesignation of areas as having attained the 1997 National Ambient Air Quality Standards for ozone. *Id.* at 383.

using publicly available data. *See* IAGO Responses at 2-3 (explaining methodology) and Exhibit 1. This chart with the capacity factors for current MPS units, from 2008 through 2017, is reattached as Attachment 1 hereto. For 2008 through 2014, the overall capacity factors for current MPS units ranged from 71% to 78%—significantly below maximum capacity. Over the past three years, the units' overall capacity factors declined, ranging between only 55% to 59% (2015: 59%; 2016: 55%; 2017: 57%).

One of the consequences of the MPS fleet's steep decline in capacity factor is annual SO_2 and NOx emission levels that have been far below Illinois EPA's proposed caps of 49,000 tons of SO_2 and 25,000 tons of NOx. A note on these calculations: we filed as Exhibit 1 to our December 11, 2017 Pre-Filed Testimony a spreadsheet including data from USEPA's Air Markets Program Data tool for the current MPS units for the year 2016. Included here as Attachments 3 through 6 are spreadsheets including the same information for the current MPS units, for the years 2013 through 2015 and 2017, again prepared through the same procedure described on pages 8 to 9 of our December 11, 2017 Pre-Filed Testimony. The following table is based on those spreadsheets:

Table 1:

Year	SO_2 Annual Tons	NOx Annual Tons
2013	43,324	18,849
2014	44,382	18,085
2015	35,706	15,309
2016	27,621[7]	13,925
2017	30,578	15,900

The disparity between Illinois EPA's proposed caps and the MPS units' actual emissions over the past five years should give the Board pause. This five-year period even includes two years—2013 and 2014—of relatively higher heat inputs. Looking at the most recent year, Illinois EPA's proposed SO_2 and NOx caps are respectively 60% and 57% higher than MPS units' actual emissions in 2017. The proposed caps bear little relation to the MPS fleet's real-world operations and, instead, would immediately allow for a significant increase in pollution.

IV. <u>EVEN IF THE MPS FLEET RETURNED TO HISTORICAL PEAK HEAT INPUTS, ILLINOIS EPA'S PROPOSED CAPS EXCEED PROJECTED ACTUAL EMISSIONS UNDER THE CURRENT MPS.</u>

Illinois EPA and Dynegy have contended in this rulemaking that the MPS fleet's operations in recent years have not been representative of normal conditions. *Cf.* 35 Ill. Adm. Code 203.104(a). This premise is questionable, at best, given the seismic changes in energy

[7] SO_2 emissions for 2013 through 2016 reflect that the Old Ameren Group was not yet at those times subject to the current MPS rate of 0.23 lb/mmBtu SO_2, which became applicable during 2017.

markets Dynegy itself has testified to as a justification for Illinois EPA's proposed amendments. *See, generally*, Pre-filed Testimony of Dean Ellis (Dec. 11, 2017) at 6-11. Even accepting the premise for the sake of argument, though, Illinois EPA's proposed caps are too high compared even with expected emissions under the current MPS at historical peak heat inputs.

Attachment 2 to this testimony is an expanded version of Attachment 1, the table showing historical capacity factors for the current MPS units. Attachment 2 further includes historical annual unit-level heat inputs, and historical annual heat inputs for the current MPS groups, overall. Like the heat inputs in Attachments 3 through 6, these historical heat inputs were obtained from USEPA's Air Markets Program Data tool. Based on those historical heat inputs, Attachment 2 then calculates what levels of annual SO_2 and NOx emissions **would have been** permissible under the overall group MPS emission rate limits currently applicable to the Dynegy and Old Ameren Groups, disregarding the Groups' actual unit-level emission rates.

As Attachment 2 shows, if the current MPS emission rate limits had been in place for the past ten years, then the current MPS units would at no point during the past ten years have been permitted to emit either 49,000 tons of SO_2 or 25,000 tons of NOx annually, based on the actual overall heat inputs for the Dynegy and Old Ameren Groups for each year in that period. To be clear: as discussed further below, when the current MPS's requirement to average together unit-level emission rates is taken into account, the current MPS units could not in any event return to peak historical capacity factors and still comply with the now effective MPS emission rate limits. Even assuming, though, that the current MPS units could otherwise return to their past-decade peak overall heat input (from 2011) of 445,904,570 mmBtu (194,717,709 mmBtu for the Dynegy Group and 251,186,861 for the Old Ameren Group), in compliance with MPS emission rate limits, the MPS would still limit the units to no more than 47,385 tons of SO_2 emissions and

23,551 tons of NOx emissions annually. So, even disregarding the units' actual emission rates, Illinois EPA's proposed annual caps on SO_2 and NOx exceed what the current MPS would permit even under the highest actual heat inputs of the past ten years.[8]

This analysis is also confirmed by the updated tables Illinois EPA included as Attachment 7 to its Responses to Pre-filed Questions filed January 12, 2018 (for convenience's sake, reattached as Attachment 7 hereto). These tables calculated projected actual emissions from the current MPS units using 2002 actual unit-level heat inputs and currently applicable MPS emission rate limits. The resulting projections were 44,920 tons of SO_2 and 22,469 tons of NOx. Again: the disparity between Illinois EPA's proposed caps and emissions reflecting real-world heat inputs should give the Board pause.

V. THE BOARD FURTHER SHOULD CONSIDER THE MPS UNITS' ACTUAL HISTORICAL EMISSION RATES.

In considering the environmental impact of Illinois EPA's proposed amendments, the Board also should consider the MPS units' actual historical emission rates. The units' emission rates are one of the basic components of their actual emissions. Moreover, the MPS requirement that unit-level emission rates be averaged to meet fleet-wide emission rate limits is one of the current rule's central features. While Illinois EPA and Dynegy have implied in this proceeding that the MPS units' emission rates are too variable to yield meaningful analysis, they have provided no evidence of the units' historical emission rates. Our analysis of actual emission rates from 2013 through 2017 demonstrates the opposite: MPS unit-level emission rates have been quite consistent. *See* IAGO Pre-Filed Testimony (Dec. 11, 2017), Ex. 1 (2016);

---

[8] The 2011 combined heat input of 445,904,570 mmBtu is 42% higher than 2017's combined heat input of 314,776,210 mmBtu.

Attachments 3-6 (2013-2015, 2017). The sole exception is Newton Unit 1's 2017 SO_2 emission rate, which appears to have been influenced by a newly installed pollution control device which has not been disclosed by Illinois EPA[9] or Dynegy to the Board in this proceeding.

Considering unit-level emission rates is key to understanding the current MPS's full environmental impact. The MPS is a fleet-wide standard. It requires an operator of MPS units to average the emission rate of each individual unit in order to meet the fleet-wide emission rate limits for the Dynegy and Old Ameren Groups. Determining compliance with the MPS therefore requires considering the annual heat input and SO_2 and NOx emissions of each individual MPS unit. If Dynegy operates a unit that emits either SO_2 or NOx at a rate higher than the applicable MPS emission rate limit, it must then also operate a unit that emits that pollutant at a rate below the limit, to comply with the limit. The consequence of this rule is that an operator of MPS units cannot run exclusively uncontrolled units; there must also be cleaner units in the generation mix. *See, e.g.*, March 6, 2018 R18-20 Hearing Transcript at 140, line 1, to 141, line 16.

This requirement to average individual units' emission rates to meet fleet-wide emission rate limits is not some unforeseen consequence of the MPS; it is a central feature. In fact, it was this averaging requirement that prompted Dynegy to seek variance relief from the MPS in 2013. At that time, Dynegy's witness Daniel P. Thompson testified that complying with the MPS's 2015 SO_2 emission rate of 0.25 lb/mmBtu for the Old Ameren Group would "effectively require each of the Newton, E.D. Edwards and Joppa energy centers to limit its respective generation to approximately one-third of its capacity." Petition for Variance, Ex. 8, Affidavit of

---

9 As stated in footnote 2, above, the Board specifically asked Illinois EPA to "[p]rovide a table listing each facility and unit along with the current pollution control equipment." IEPA January 12, 2018 Responses to Pre-Filed Questions at 7, Ques.10.

Daniel P. Thompson at 6, *Illinois Power Holdings, LLC v. IEPA*, PCB 14-10 (July 22, 2013). Clearly, Dynegy's prediction did not come to pass, given that the Old Ameren Group—including units at Newton, E.D. Edwards, and Joppa—currently complies with the even more stringent 2017 SO_2 emission rate of 0.23 lb/mmBtu. Nevertheless: ignoring the MPS's averaging requirement and the MPS units' unit-level emission rates turns a blind eye as to why this proceeding is before the Board.

Given the centrality of the averaging requirement to the MPS, it is puzzling why Illinois EPA did not consider it in proposing its caps. Illinois EPA has asked that the Board consider its proposed caps using as a baseline the current MPS units' "allowable emissions" operating at maximum capacity, at the highest emission rates allowed by the MPS. *See* IEPA Technical Support Document at 8-11. When asked during the January 17, 2018 hearing if the MPS fleet as currently controlled could actually operate at maximum capacity in compliance with the MPS's fleet-wide emission rate limits, though, Illinois EPA's witness testified that he did not know. January 17, 2018 R18-20 Hearing Transcript at 48, lines 13-24. In other words, Illinois EPA completely disregarded one of the MPS's central features when it developed its current proposal.

The reality is that the Old Ameren Group, as currently controlled, cannot operate at maximum capacity and comply with the MPS SO_2 emission rate limit. This was true when Dynegy said it in 2013 and it is true today. We established this point in Table 10 to our December 11, 2017 Pre-filed Testimony, which showed that the Old Ameren Group could not operate at maximum capacity in compliance with the MPS at its unit-level emission rates from 2016—the most recent available emission rates at the time we prepared the testimony. Illinois EPA and Dynegy then, at various points during subsequent hearings, implied that use of only

2016 emission rates presents a myopic view of the MPS units' operations—though failed to present any evidence of their own on historical emission rates. *See*, *e.g.*, January 17, 2018 R18-20 Hearing Transcript at 49, lines 4-12 (Illinois EPA stating that it could not consider the MPS units' actual emission rates without making "assumptions about the emission rates of other units that they are not required to meet on a unit or source-specific basis").

To address these purported concerns, we calculated the actual annual unit-level emission rates for each of the current MPS units for 2013 through 2015 and 2017, in the same manner described on page 8 of our December 11, 2017 Pre-Filed Testimony. *See* Attachments 3-6. In short: annual unit-level SO_2 and NOx emission rates have been consistent over the past five years throughout both the Dynegy and Old Ameren Group. Expressed to two decimal points—as are the emission rates in the MPS—the units at each MPS plant has had the following range of annual SO_2 emission rates:[10]

Table 2:

Plant	**Range of Annual SO_2 Emission Rates, 2013-2017 (lb/mmBtu)**
Baldwin	0.07 – 0.08
Havana	0.07 – 0.08
Hennepin	0.42 – 0.50
Coffeen	0.00 – 0.01
Duck Creek	0.00 – 0.02
Edwards	0.41 – 0.45
Joppa	0.39 – 0.51
Newton	0.40 – 0.51 (2013-2016); 0.29 (2017)

As demonstrated by these historical rates, the four plants identified by Illinois EPA in its testimony to have controls for SO_2—Baldwin, Havana, Coffeen, and Duck Creek—have

[10] The NOx emission rates are more unit-specific, as opposed to plant-specific, relative to SO_2 emission rates, but nevertheless also are consistent from year to year. *See* IAGO Pre-Filed Testimony (Dec. 11, 2017), Ex. 1; Attachments 3-6.

remained nearly identical from year to year. *See* IEPA Responses to Pre-Filed Questions (Jan. 12, 2018) at 7 (table identifying SO_2 and NOx controls at MPS plants). Plants for which Illinois EPA has not identified controls—Hennepin, Edwards, Joppa, and Newton—have slightly more variation, based on the sulfur content of coal burned that year, but still remain bounded between 0.39 lb/mmBtu and 0.51 lb/mmBtu SO_2, at the most extreme ranges. Accordingly, there is no need for Illinois EPA to make any "assumptions" about emission rates, January 17, 2018 R18-20 Hearing Transcript at 49, lines 4-12; these are the plants' actual historical emission rates for five years, and they are steady.

The one notable exception to the above paragraph is Newton Unit 1 in 2017. We hypothesize that Newton's 2017 SO_2 emission rate was impacted by Dynegy's operation of pollution control equipment at the plant. Included as Attachments 8 and 9 are a May 24, 2016 construction permit and a June 9, 2017 revised construction permit issued by Illinois EPA to Dynegy, related to such equipment. The June 9, 2017 revised permit authorizes "ductwork sorbent injection . . . to be conducted on an on-going basis on [Newton] Boiler 1." Attachment 9 at 1.b.i. It is unclear to us why Illinois EPA did not identify this as pollution control equipment for SO_2 in its January 12, 2018 Responses to Pre-Filed Questions (question 10, p. 7), or why Dynegy has not corrected Illinois EPA's omission.

The previously unidentified Newton pollution control equipment provides one good example of why "layered" emission rates over the Illinois EPA's proposed emission caps would be beneficial, if the Board decides to proceed with this rulemaking. Under the current MPS, unit-level emission rates for both SO_2 and NOx have been steady. *See* IAGO Pre-Filed Testimony (Dec. 11, 2017), Ex. 1; Attachments 3-6. If the MPS is amended to repeal the existing fleet-wide emission rates, though, there are no guarantees they will remain so.

Deactivating pollution control equipment, like the ductwork sorbent injection system installed at Newton, would be a clear instance of a step backward, environmentally—but it would be permitted by Illinois EPA's proposed amendments. We therefore offer the MPS units' actual historical unit-level emission rates for the Board's consideration as a basis for setting "layered" emission rates, if the Board finds any merit in amending the MPS for the unsupported notion of providing Dynegy with "operational flexibility."

VI. CONSIDERING BOTH ACTUAL HISTORICAL HEAT INPUTS AND EMISSION RATES, PROJECTED ACTUAL EMISSIONS UNDER THE MPS ARE WELL BELOW ILLINOIS EPA'S PROPOSED CAPS.

Taking into account both actual historical heat inputs and emission rates, it is clear that Illinois EPA's proposed caps would permit significantly more pollution than the current MPS. As such, this proposal clearly conflicts with Title II of the Illinois Environmental Protection Act's stated purpose, which is to "restore, maintain, and enhance the purity of the air of this State." 415 ILCS 5/8 (2016). Illinois EPA has posited that, while its proposed amendments might permit an increase in actual emissions if MPS units have higher capacity factors in the future, the current MPS also would permit similar—or even greater—increases in that scenario. *See, e.g.*, March 6, 2018 R18-20 Hearing Transcript at 139, lines 3-24.

Illinois EPA is incorrect, as is demonstrated by Attachment 9. This spreadsheet takes as a basis the actual 2002 heat inputs for each of the current MPS units, and then applies actual 2017 unit-level emission rates to determine what levels of SO_2 and NOx emissions would be permitted under both the current MPS and Illinois EPA's proposed amendments. We selected 2002 heat inputs because: (1) that data previously has been relied upon by Illinois EPA to show compliance with the Regional Haze Rule; and (2) the overall 2002 heat input of 420,531,000 mmBtu is comparable to actual overall heat inputs during 2008 through 2014, years which Illinois EPA and Dynegy have asserted are more representative of the MPS fleet's operations than 2015 through 2017.[11] We selected 2017 emission rates because: (1) they are the most current data; and (2) of the five years between 2013 and 2017, the Old Ameren Group's unit-level SO_2 emission rates allowed for the highest heat input without exceeding the current MPS's 0.23 lb/mmBtu emission rate limit. *Compare* "Table 10" on IAGO Pre-Filed Testimony (Dec. 11, 2017), Ex. 1, and Attachments 3-6. The results are as follows:

Table 4:

2002 Heat Inputs with 2017 Unit-Level Emission Rates	Annual SO_2 Emissions (Tons)	Annual NOx Emissions
Current MPS	34,094	18,920
Proposed Amendments	46,064	21,672

As Attachment 9 shows, were the MPS fleet even capable of again reaching 2002 historical actual heat inputs, the current MPS would not allow Dynegy to operate the Old Ameren Group at those levels, because the Old Ameren Group units lack adequate SO_2 controls. The Old Ameren Group's operations would be constrained by the MPS SO_2 emission rate, and its SO_2 and NOx emissions would be limited accordingly. Simply put: under the current MPS, Dynegy cannot operate its higher-polluting uncontrolled units as intensively as it did before, relative to controlled units, because Dynegy has intentionally chosen not to install the pollution controls that would allow it to comply with the current MPS. Illinois EPA's proposed amendments would remove that limitation and allow Dynegy or Vistra to increase SO_2 and NOx pollution, thereby rewarding the failure to invest in the plants, all to the detriment of the environment.

---

[11] As stated above, Illinois EPA and Dynegy's contentions in this regard are questionable, at best, given the drastic changes in energy markets in recent years, and while one year's data might constitute an outlier, three years of data represents a trend that appears to be the new "normal."

Accordingly, we maintain that the Board should reject Illinois EPA's proposal. If the Board does determine to proceed with this rulemaking, then we suggest that the Board reduce Illinois EPA's proposed caps at least to 34,094 tons for SO_2 and 18,920 tons for NOx. We further suggest that any caps the Board sets should decline when an MPS unit is mothballed or retired. Illinois EPA proposes that the operator's caps should decline when it sells a plant, but not when it retires or mothballs a plant. Letting the operator keep caps upon retirement or mothballing a plant, but not upon sale, would encourage greater pollution and, moreover, incentivize retirement over sale.

VII. CONCLUSION

We do not support the Illinois EPA's proposed SO_2 annual emission cap of 49,000 tons nor the NOx annual emission cap of 25,000 tons. Rather, Dynegy should be required to comply with the emission standards that it and Ameren, its predecessor in ownership, agreed to when the MPS was created. The Board should therefore reject Illinois EPA's proposal. If the Board determines that the record supports the use of mass-based standards, the Board should reduce Illinois EPA's proposed caps at least to 34,094 tons for SO_2 and 18,920 tons for NOx and, in addition, require that any such caps be reduced if and when Dynegy retires or mothballs units.

Further, if the Board adopts mass-based standards, it also should consider "layering" one or more emission rate limits to ensure use of good pollution controls at the MPS units.

Dated: April 3, 2018

Respectfully submitted,

PEOPLE OF THE STATE OF ILLINOIS,
by LISA MADIGAN,

Attorney General of the State of Illinois,
MATTHEW J. DUNN, Chief
Environmental Enforcement/
Asbestos Litigation Division

Andrew Armstrong

By: ______________________________

ANDREW ARMSTRONG
Chief, Environmental Bureau/Springfield
Illinois Attorney General's Office
500 South Second Street
Springfield, Illinois 62706
(217) 782-7968
aarmstrong@atg.state.il.us

Of counsel:

STEPHEN J. SYLVESTER
Senior Assistant Attorney General
(312) 814-2087
ssylvester@atg.state.il.us

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 1

Exhibit 1 - MPS Units Capacity Factors (AG Response Questions Raised First Hearing Filed 2/16/18)

Facility Name	Unit ID	2017 Gross Load (MW-h)	2016 Gross Load (MW-h)	2015 Gross Load (MW-h)	2014 Gross Load (MW-h)	2013 Gross Load (MW-h)	2012 Gross Load (MW-h)	2011 Gross Load (MW-h)	2010 Gross Load (MW-h)	2009 Gross Load (MW-h)	2008 Gross Load (MW-h)	Nameplate Capacity (MW)	2017 Capacity Factor	2016 Capacity Factor	2015 Capacity Factor	2014 Capacity Factor	2013 Capacity Factor	2012 Capacity Factor	2011 Capacity Factor	2010 Capacity Factor	2009 Capacity Factor	2008 Capacity Factor
Baldwin	1	4256973	3579945	3929009	3612677	4353264	4382095	4256142	4922426	4719810	4365766	625	78%	65%	72%	66%	80%	80%	78%	90%	86%	80%
Baldwin	2	4248869	4142070	3016142	4529481	4977489	4063944	4872441	5076725	3740462	4874545	635	76%	74%	54%	81%	89%	73%	88%	91%	67%	88%
Baldwin	3	0	2907612	4220738	4531695	4211091	4794276	5232122	3547576	4500586	4634595	635	0%	52%	76%	81%	76%	86%	94%	64%	81%	83%
Coffeen	1	2149649	1645863	1663873	2151742	1821705	1945318	2286431	2300356	1586382	2415664	389	63%	48%	49%	63%	53%	57%	67%	68%	47%	71%
Coffeen	2	3960975	3436013	3324374	3635208	3333747	3620176	3213509	3073162	2948670	3515473	617	73%	64%	62%	67%	62%	67%	59%	57%	55%	65%
Duck Creek	1	2166840	2338467	2363610	2477495	2766167	3075539	2327215	2827797	2137973	2482081	441	56%	61%	61%	64%	72%	80%	60%	73%	55%	64%
E D Edwards	2	1262963	1089069	1698538	1854000	1838296	1879308	1916844	1818425	1878918	1565992	281	51%	44%	69%	75%	75%	76%	78%	74%	76%	64%
E D Edwards	3	2046863	1938365	1475139	2111602	2302982	1937026	2332239	2446622	2390773	2187691	364	64%	61%	46%	66%	72%	61%	73%	77%	75%	69%
Havana	9	2848787	2671713	2115992	2850484	3153270	3023729	3290873	3356096	2280409	3060557	488	67%	62%	49%	67%	74%	71%	77%	79%	53%	72%
Hennepin	1	438327	416864	439325	459685	359877	515218	577749	573819	533447	397677	75	67%	63%	67%	70%	55%	78%	88%	87%	81%	61%
Hennepin	2	1378893	1158049	1246904	1379725	1411586	1808108	1804087	1868434	1775299	1339958	231	68%	57%	62%	68%	70%	89%	89%	92%	88%	66%
Joppa	1	875026	752282	956900	1312296	1292822	1260495	1418830	1456298	1424827	1151113	183	55%	47%	60%	82%	81%	79%	89%	91%	89%	72%
Joppa	2	801348	736600	871481	1320187	1256764	1233258	1194562	1397275	1318607	1516512	183	50%	46%	54%	82%	78%	77%	75%	87%	82%	95%
Joppa	3	685802	428451	840144	1247131	1186607	1102056	1361558	1341577	1365346	1497672	183	43%	27%	52%	78%	74%	69%	85%	84%	85%	93%
Joppa	4	530810	682622	921854	1333425	1267827	1225340	1437495	1439559	847003	1478670	183	33%	43%	58%	83%	79%	76%	90%	90%	53%	92%
Joppa	5	627033	382421	930759	1191697	1231189	1027743	1416709	1373654	1324612	1485316	183	39%	24%	58%	74%	77%	64%	88%	86%	83%	93%
Joppa	6	729089	476243	810991	1317637	1215881	1151848	1444091	1407797	1346374	1504067	183	45%	30%	51%	82%	76%	72%	90%	88%	84%	94%
Newton	1	3546555	2348892	2842906	3490220	3336394	3637379	3964715	4200305	4374462	4386205	617	66%	43%	53%	65%	62%	67%	73%	78%	81%	81%
TOTAL		32554802	31131541	33668679	40806386	41316958	41682856	44347613	44427903	40493961	43859554	6496	57%	55%	59%	72%	73%	73%	78%	78%	71%	77%

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 2

Exhibit 1 - MPS Units Capacity Factors (AG Response Questions Raised First Hearing Filed 2/16/18)

Facility Name	Unit ID	2017 Gross Load (MW-h)	2016 Gross Load (MW-h)	2015 Gross Load (MW-h)	2014 Gross Load (MW-h)	2013 Gross Load (MW-h)	2012 Gross Load (MW-h)	2011 Gross Load (MW-h)	2010 Gross Load (MW-h)	2009 Gross Load (MW-h)	2008 Gross Load (MW-h)	Nameplate Capacity (MW)	2017 Capacity Factor	2016 Capacity Factor	2015 Capacity Factor	2014 Capacity Factor	2013 Capacity Factor	2012 Capacity Factor	2011 Capacity Factor	2010 Capacity Factor	2009 Capacity Factor	2008 Capacity Factor
Baldwin	1	4256973	3579945	3929009	3612677	4353264	4382095	4256142	4922426	4719810	4365766	625	78%	65%	72%	66%	80%	80%	78%	90%	86%	80%
Baldwin	2	4248869	4142070	3016142	4529481	4977489	4063944	4872441	5076725	3740462	4874545	635	76%	74%	54%	81%	89%	73%	88%	91%	67%	88%
Baldwin	3	0	2907612	4220738	4531695	4211091	4794276	5232122	3547576	4500586	4634595	635	0%	52%	76%	81%	76%	86%	94%	64%	81%	83%
Coffeen	1	2149649	1645863	1663873	2151742	1821705	1945318	2286431	2300356	1586382	2415664	389	63%	48%	49%	63%	53%	57%	67%	68%	47%	71%
Coffeen	2	3960975	3436013	3324374	3635208	3333747	3620176	3213509	3073162	2948670	3515473	617	73%	64%	62%	67%	62%	67%	59%	57%	55%	65%
Duck Creek	1	2166840	2338467	2363610	2477495	2766167	3075539	2327215	2827797	2137973	2482081	441	56%	61%	61%	64%	72%	80%	60%	73%	55%	64%
E D Edwards	2	1262963	1089069	1698538	1854000	1838296	1879308	1916844	1818425	1878918	1565992	281	51%	44%	69%	75%	75%	76%	78%	74%	76%	64%
E D Edwards	3	2046863	1938365	1475139	2111602	2302982	1937026	2332239	2446622	2390773	2187691	364	64%	61%	46%	66%	72%	61%	73%	77%	75%	69%
Havana	9	2848787	2671713	2115992	2850484	3153270	3023729	3290873	3356096	2280409	3060557	488	67%	62%	49%	67%	74%	71%	77%	79%	53%	72%
Hennepin	1	438327	416864	439325	459685	359877	515218	577749	573819	533447	397677	75	67%	63%	67%	70%	55%	78%	88%	87%	81%	61%
Hennepin	2	1378893	1158049	1246904	1379725	1411586	1808108	1804087	1868434	1775299	1339958	231	68%	57%	62%	68%	70%	89%	89%	92%	88%	66%
Joppa	1	875026	752282	956900	1312296	1292822	1260495	1418830	1456298	1424827	1151113	183	55%	47%	60%	82%	81%	79%	89%	91%	89%	72%
Joppa	2	801348	736600	871481	1320187	1256764	1233258	1194562	1397275	1318607	1516512	183	50%	46%	54%	82%	78%	77%	75%	87%	82%	95%
Joppa	3	685802	428451	840144	1247131	1186607	1102056	1361558	1341577	1365346	1497672	183	43%	27%	52%	78%	74%	69%	85%	84%	85%	93%
Joppa	4	530810	682622	921854	1333425	1267827	1225340	1437495	1439559	847003	1478670	183	33%	43%	58%	83%	79%	76%	90%	90%	53%	92%
Joppa	5	627033	382421	930759	1191697	1231189	1027743	1416709	1373654	1324612	1485316	183	39%	24%	58%	74%	77%	64%	88%	86%	83%	93%
Joppa	6	729089	476243	810991	1317637	1215881	1151848	1444091	1407797	1346374	1504067	183	45%	30%	51%	82%	76%	72%	90%	88%	84%	94%
Newton	1	3546555	2348892	2842906	3490220	3336394	3637379	3964715	4200305	4374462	4386205	617	66%	43%	53%	65%	62%	67%	73%	78%	81%	81%
TOTAL		32554802	31131541	33668679	40806386	41316958	41682856	44347613	44427903	40493961	43859554	6496	57%	55%	59%	72%	73%	73%	78%	78%	71%	77%

		2017 Heat Input (mmBtu)	2016 Heat Input (mmBtu)	2015 Heat Input (mmBtu)	2014 Heat Input (mmBtu)	2013 Heat Input (mmBtu)	2012 Heat Input (mmBtu)	2011 Heat Input (mmBtu)	2010 Heat Input (mmBtu)	2009 Heat Input (mmBtu)	2008 Heat Input (mmBtu)
DYNEGY GROUP											
Baldwin	1	38824663	32659083	37866256	32456229	39629830	43725328	37783602	42860896	42376555	38900401
Baldwin	2	40385824	38830110	28230422	42613958	46281964	38467310	45092055	46480909	34951998	47395103
Baldwin	3	0	30643341	42135390	44089201	41921039	48467691	50791868	34012081	43656835	44255109
Havana	9	30567133	30279146	23344525	31583549	34312338	32957602	36833553	35225775	22274295	30758032
Hennepin	1	4508524	4417514	4601595	4720259	3662676	5255799	5907566	5916688	5566820	4277351
Hennepin	2	14201402	12095937	12788515	14008763	13966816	18303983	18309065	19085795	18278934	13264585
TOTAL		**128487546**	**148925131**	**148966703**	**169471959**	**179774663**	**187177713**	**194717709**	**183582144**	**167105437**	**178850581**
MPS SO2 (tons)		**12206**	**14148**	**14152**	**16100**	**17079**	**17782**	**18498**	**17440**	**15875**	**16991**
MPS NOx (tons)		**6424**	**7446**	**7448**	**8474**	**8989**	**9359**	**9736**	**9179**	**8355**	**8943**
OLD AMEREN GROUP											
Coffeen	1	19939412	15328145	15993139	20571870	18461732	19425263	23901997	24410806	17549206	26759121
Coffeen	2	39101271	33234005	33529517	35557130	32217458	34734221	33598366	32608370	30016843	38553048
Duck Creek	1	19985699	23470382	22722935	22385698	23561779	25219962	24159532	28849323	21407745	23856295
E D Edwards	2	13212705	10948007	16917465	18609882	18193244	17880205	20921358	17992114	19069150	16796596
E D Edwards	3	17698112	17244294	13527349	20704034	22552954	18872502	25293516	26068920	24994709	24449330
Joppa	1	8983253	7703571	9580656	12635915	12547946	12687192	14397390	14851874	14380768	11899023
Joppa	2	8140886	7518431	8655055	12687892	12120069	12343639	11839036	14204176	13239471	15860012
Joppa	3	7034467	4327176	8363510	12153206	11530620	11223231	13628892	13382030	13958821	14928537
Joppa	4	5244525	6811839	9138359	12939835	12272250	12426971	14356229	14331786	8451146	14682159
Joppa	5	6357587	4027068	9581988	11893458	12289122	10838724	14674513	14188501	13595175	15084592
Joppa	6	7292449	4937499	8445632	13094796	12069593	12063815	14927835	14506686	13689006	15179949
Newton	1	33298298	23918941	27378355	32214778	31216532	35688037	39488197	42601247	43565338	42347365
TOTAL		**186288664**	**159469358**	**183833960**	**225448494**	**219033299**	**223403762**	**251186861**	**257995833**	**233917378**	**260396027**
MPS SO2 (tons)		**21423**	**18339**	**21141**	**25927**	**25189**	**25691**	**28886**	**29670**	**26900**	**29946**
MPS NOx (tons)		**10246**	**8771**	**10111**	**12400**	**12047**	**12287**	**13815**	**14190**	**12865**	**14322**
COMBINED											
TOTAL		**314776210**	**308394489**	**332800663**	**394920453**	**398807962**	**410581475**	**445904570**	**441577977**	**401022815**	**439246608**
MPS SO2 (tons)		**33630**	**32487**	**35293**	**42026**	**42267**	**43473**	**47385**	**47110**	**42776**	**46936**
MPS NOx (tons)		**16670**	**16217**	**17559**	**20873**	**21036**	**21646**	**23551**	**23369**	**21221**	**23264**

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
<u>ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE</u>

ATTACHMENT 3

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate	Max NOx Tons	Max Group Nox Rate
IL	Baldwin	889	1	2013	4353264	1513	1388	39629830	0.0764	0.0701	625	80%	6439	56405640	2154	0.0764	1976	0.0701
IL	Baldwin	889	2	2013	4977489	1714	1670	46281964	0.0741	0.0722	635	89%	5985	52428600	1942	0.0753	1892	0.0711
IL	Baldwin	889	3	2013	4211091	1576	1902	41921039	0.0752	0.0907	635	76%	6400	56064000	2108	0.0752	2543	0.0778
IL	Havana	891	9	2013	3153270	1130	1336	34312338	0.0659	0.0779	488	74%	5518	48337680	1592	0.0731	1883	0.0778
IL	Hennepin	892	1	2013	359877	883	259	3662676	0.4821	0.1413	75	55%	802	7025520	1694	0.0862	496	0.0798
IL	Hennepin	892	2	2013	1411586	3396	989	13966816	0.4863	0.1417	231	70%	2518	22057680	5364	0.1226	1562	0.0854
IL	Coffeen	861	1	2013	1821705	61	635	18461732	0.0066	0.0688	389	53%	3282	28750320	95	0.0066	989	0.0688
IL	Coffeen	861	2	2013	3333747	47	1251	32217458	0.0029	0.0776	617	62%	5544	48565440	71	0.0043	1885	0.0744
IL	Duck Creek	6016	1	2013	2766167	231	1268	23561779	0.0196	0.1076	441	72%	5025	44019000	431	0.0099	2368	0.0864
IL	ED Edwards	856	2	2013	1838296	4107	1752	18193244	0.4515	0.1926	281	75%	3321	29091960	6568	0.0953	2801	0.1069
IL	ED Edwards	856	3	2013	2302982	4852	777	22552954	0.4303	0.0689	364	72%	4594	40243440	8658	0.1660	1387	0.0989
IL	Joppa	887	1	2013	1292822	2843	730	12547946	0.4532	0.1164	183	81%	2300	20148000	4565	0.1934	1172	0.1006
IL	Joppa	887	2	2013	1256764	2741	711	12120069	0.4523	0.1173	183	78%	2300	20148000	4557	0.2160	1181	0.1020
IL	Joppa	887	3	2013	1186607	2622	614	11530620	0.4549	0.1066	183	74%	2300	20148000	4582	0.2352	1073	0.1024
IL	Joppa	887	4	2013	1267827	2783	657	12272250	0.4535	0.1071	183	79%	2300	20148000	4569	0.2514	1079	0.1028
IL	Joppa	887	5	2013	1231189	2802	670	12289122	0.4560	0.1091	183	77%	2300	20148000	4594	0.2655	1099	0.1032
IL	Joppa	887	6	2013	1215881	2751	657	12069593	0.4559	0.1089	183	76%	2300	20148000	4593	0.2779	1097	0.1036
IL	Newton	6017	1	2013	3336394	7270	1583	31216532	0.4658	0.1014	617	62%	7449	65253240	15196	0.3104	3309	0.1032
					41316958	43324	18849	398807962	0.2173	0.0945	6496	73%						

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2013 SO2 Emissions	10213		179774663	0.114	Table 3
Dynegy Group 2013 SO2 Emissions Minus Baldwin 1, 3	7123		98223794	0.145	Table 4
Dynegy Group 2013 NOx Emissions		7545	179774663	0.084	Table 5
Dynegy Group 2013 NOx Emissions Minus Baldwin 1, 3		4255	98223794	0.087	Table 6
Old Ameren Group 2013 SO2 Emissions	33111		219033299	0.302	Table 7
Old Ameren Group 2013 NOx Emissions		11305	219033299	0.103	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		14853			Table 9
Dynegy Group NOx Emissions at Max Heat Input		10353			Table 11
Old Ameren NOx Emissions Max Heat Input		19441			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		40235	317257093	0.2536	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		15559	317257093	0.0981	Table 16

Table 10:

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
IL	Coffeen	861	2	2013	3333747	47	1251	32217458	0.0029	0.0776	617	62%	5544	48565440	71	0.0029
IL	Coffeen	861	1	2013	1821705	61	635	18461732	0.0066	0.0688	389	53%	3282	28750320	95	0.0043
IL	Duck Creek	6016	1	2013	2766167	231	1268	23561779	0.0196	0.1076	441	72%	5025	44019000	431	0.0099
IL	ED Edwards	856	3	2013	2302982	4852	777	22552954	0.4303	0.0689	364	72%	4594	40243440	8658	0.1146
IL	ED Edwards	856	2	2013	1838296	4107	1752	18193244	0.4515	0.1926	281	75%	3321	29091960	6568	0.1660
IL	Joppa	887	2	2013	1256764	2741	711	12120069	0.4523	0.1173	183	78%	2300	20148000	4557	0.1933
IL	Joppa	887	1	2013	1292822	2843	730	12547946	0.4532	0.1164	183	81%	2300	20148000	4565	0.2160
IL	Joppa	887	4	2013	1267827	2783	657	12272250	0.4535	0.1071	183	79%	2300	20148000	4569	0.2351
															29515	

Combined MPS SO2 Emissions at Max Heat Input (tons) **44367**

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 4

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate	Max NOx Tons	Max Group Nox Rate
IL	Baldwin	889	1	2014	3612677	1213	1188	32456229	0.0748	0.0732	625	66%	6439	56405640	2109	0.0748	2065	0.0732
IL	Baldwin	889	2	2014	4529481	1490	1475	42613958	0.0699	0.0692	635	81%	5985	52428600	1834	0.0724	1815	0.0713
IL	Baldwin	889	3	2014	4531695	1706	2040	44089201	0.0774	0.0926	635	81%	6400	56064000	2169	0.0741	2594	0.0785
IL	Havana	891	9	2014	2850484	1068	1181	31583549	0.0676	0.0748	488	67%	5518	48337680	1635	0.0727	1807	0.0777
IL	Hennepin	892	1	2014	459685	1002	347	4720259	0.4246	0.1470	75	70%	802	7025520	1492	0.0839	516	0.0799
IL	Hennepin	892	2	2014	1379725	2959	1019	14008763	0.4224	0.1455	231	68%	2518	22057680	4659	0.1147	1605	0.0859
IL	Coffeen	861	1	2014	2151742	22	656	20571870	0.0022	0.0638	389	63%	3282	28750320	31	0.0022	917	0.0638
IL	Coffeen	861	2	2014	3635208	10	1223	35557130	0.0006	0.0688	617	67%	5544	48565440	13	0.0012	1670	0.0669
IL	Duck Creek	6016	1	2014	2477495	240	1065	22385698	0.0214	0.0952	441	64%	5025	44019000	472	0.0085	2094	0.0772
IL	ED Edwards	856	2	2014	1854000	4021	1723	18609882	0.4321	0.1851	281	75%	3321	29091960	6286	0.0904	2693	0.0980
IL	ED Edwards	856	3	2014	2111602	4244	704	20704034	0.4100	0.0680	364	66%	4594	40243440	8249	0.1579	1367	0.0917
IL	Joppa	887	1	2014	1312296	3080	701	12635915	0.4875	0.1109	183	82%	2300	20148000	4911	0.1894	1117	0.0935
IL	Joppa	887	2	2014	1320187	3093	710	12687892	0.4876	0.1119	183	82%	2300	20148000	4912	0.2154	1127	0.0951
IL	Joppa	887	3	2014	1247131	2950	654	12153206	0.4855	0.1077	183	78%	2300	20148000	4891	0.2371	1085	0.0961
IL	Joppa	887	4	2014	1333425	3137	696	12939835	0.4849	0.1076	183	83%	2300	20148000	4885	0.2555	1084	0.0970
IL	Joppa	887	5	2014	1191697	2866	602	11893458	0.4819	0.1012	183	74%	2300	20148000	4854	0.2711	1020	0.0973
IL	Joppa	887	6	2014	1317637	3154	662	13094796	0.4818	0.1011	183	82%	2300	20148000	4853	0.2848	1018	0.0975
IL	Newton	6017	1	2014	3490220	8126	1440	32214778	0.5045	0.0894	617	65%	7449	65253240	16460	0.3228	2917	0.0961
					40806387	44382	18085	394920453	0.2248	0.0916	6496	72%						

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2014 SO2 Emissions	9439		169471959	0.111	Table 3
Dynegy Group 2014 SO2 Emissions Minus Baldwin 1, 3	6519		92926529	0.140	Table 4
Dynegy Group 2014 NOx Emissions		7251	169471959	0.086	Table 5
Dynegy Group 2014 NOx Emissions Minus Baldwin 1, 3		4022	92926529	0.087	Table 6
Old Ameren Group 2014 SO2 Emissions	34944		225448494	0.310	Table 7
Old Ameren Group 2014 NOx Emissions		10834	225448494	0.096	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		13896			Table 9
Dynegy Group NOx Emissions at Max Heat Input		10403			Table 11
Old Ameren NOx Emissions Max Heat Input		18109			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		41463	318375023	0.2605	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		14857	318375023	0.0933	Table 16

Table 10:

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
IL	Coffeen	861	2	2014	3635208	10	1223	35557130	0.0006	0.0688	617	67%	5544	48565440	13	0.0006
IL	Coffeen	861	1	2014	2151742	22	656	20571870	0.0022	0.0638	389	63%	3282	28750320	31	0.0012
IL	Duck Creek	6016	1	2014	2477495	240	1065	22385698	0.0214	0.0952	441	64%	5025	44019000	472	0.0085
IL	ED Edwards	856	3	2014	2111602	4244	704	20704034	0.4100	0.0680	364	66%	4594	40243440	8249	0.1085
IL	ED Edwards	856	2	2014	1854000	4021	1723	18609882	0.4321	0.1851	281	75%	3321	29091960	6286	0.1579
IL	Joppa	887	5	2014	1191697	2866	602	11893458	0.4819	0.1012	183	74%	2300	20148000	4854	0.1888
IL	Joppa	887	4	2014	1333425	3137	696	12939835	0.4849	0.1076	183	83%	2300	20148000	4885	0.2147
IL	Joppa	887	3	2014	1247131	2950	654	12153206	0.4855	0.1077	183	78%	2300	20148000	4891	0.2364
															29682	

Combined MPS SO2 Emissions at Max Heat Input (tons) **43579**

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 5

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate	Max NOx Tons	Max Group Nox Rate
IL	Baldwin	889	1	2015	3929009	1503	1384	37866256	0.0794	0.0731	625	72%	6439	56405640	2238	0.0794	2061	0.0731
IL	Baldwin	889	2	2015	3016142	1062	985	28230422	0.0753	0.0698	635	54%	5985	52428600	1973	0.0774	1829	0.0715
IL	Baldwin	889	3	2015	4220738	1595	1879	42135390	0.0757	0.0892	635	76%	6400	56064000	2122	0.0768	2500	0.0775
IL	Havana	891	9	2015	2115992	858	892	23344525	0.0735	0.0764	488	49%	5518	48337680	1777	0.0761	1847	0.0773
IL	Hennepin	892	1	2015	439325	1048	317	4601595	0.4554	0.1379	75	67%	802	7025520	1600	0.0882	484	0.0792
IL	Hennepin	892	2	2015	1246904	2922	893	12788515	0.4569	0.1396	231	62%	2518	22057680	5039	0.1217	1540	0.0847
IL	Coffeen	861	1	2015	1663873	21	567	15993139	0.0027	0.0709	389	49%	3282	28750320	38	0.0027	1019	0.0709
IL	Coffeen	861	2	2015	3324374	16	1048	33529517	0.0010	0.0625	617	62%	5544	48565440	23	0.0016	1518	0.0656
IL	Duck Creek	6016	1	2015	2363610	78	1012	22722935	0.0069	0.0891	441	61%	5025	44019000	152	0.0035	1961	0.0741
IL	ED Edwards	856	2	2015	1698538	3609	1683	16917465	0.4266	0.1989	281	69%	3321	29091960	6205	0.0853	2893	0.0983
IL	ED Edwards	856	3	2015	1475139	2826	458	13527349	0.4179	0.0677	364	46%	4594	40243440	8408	0.1555	1363	0.0918
IL	Joppa	887	1	2015	956900	2360	548	9580656	0.4927	0.1144	183	60%	2300	20148000	4963	0.1877	1153	0.0940
IL	Joppa	887	2	2015	871481	2131	502	8655055	0.4924	0.1161	183	54%	2300	20148000	4960	0.2143	1170	0.0959
IL	Joppa	887	3	2015	840144	2070	458	8363510	0.4949	0.1095	183	52%	2300	20148000	4986	0.2368	1103	0.0970
IL	Joppa	887	4	2015	921854	2268	501	9138359	0.4964	0.1096	183	58%	2300	20148000	5000	0.2561	1104	0.0979
IL	Joppa	887	5	2015	930759	2332	515	9581988	0.4866	0.1076	183	58%	2300	20148000	4902	0.2721	1084	0.0986
IL	Joppa	887	6	2015	810991	2070	441	8445632	0.4901	0.1044	183	51%	2300	20148000	4938	0.2862	1052	0.0990
IL	Newton	6017	1	2015	2842906	6938	1226	27378355	0.5068	0.0895	617	53%	7449	65253240	16537	0.3244	2922	0.0973
					33668679	35707	15309	332800663	0.2146	0.0920	6496	59%						

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2015 SO2 Emissions	8988		148966703	0.121	Table 3
Dynegy Group 2015 SO2 Emissions Minus Baldwin 1, 3	5890		68965057	0.171	Table 4
Dynegy Group 2015 NOx Emissions		6350	148966703	0.085	Table 5
Dynegy Group 2015 NOx Emissions Minus Baldwin 1, 3		3087	68965057	0.090	Table 6
Old Ameren Group 2015 SO2 Emissions	26719		183833960	0.291	Table 7
Old Ameren Group 2015 NOx Emissions		8959	183833960	0.097	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		14750			Table 9
Dynegy Group NOx Emissions at Max Heat Input		10262			Table 11
Old Ameren NOx Emissions Max Heat Input		18340			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		32609	252799017	0.2580	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		12046	252799017	0.0953	Table 16

Table 10:

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO_2 (tons)	NO_x (tons)	Heat Input (MMBtu)	SO_2 Rate	NO_x Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO_2 tons	Max Group SO_2 Rate
IL	Coffeen	861	2	2015	3324374	16	1048	33529517	0.0010	0.0625	617	62%	5544	48565440	23	0.0010
IL	Coffeen	861	1	2015	1663873	21	567	15993139	0.0027	0.0709	389	49%	3282	28750320	38	0.0016
IL	Duck Creek	6016	1	2015	2363610	78	1012	22722935	0.0069	0.0891	441	61%	5025	44019000	152	0.0035
IL	ED Edwards	856	3	2015	1475139	2826	458	13527349	0.4179	0.0677	364	46%	4594	40243440	8408	0.1067
IL	ED Edwards	856	2	2015	1698538	3609	1683	16917465	0.4266	0.1989	281	69%	3321	29091960	6205	0.1555
IL	Joppa	887	5	2015	930759	2332	515	9581988	0.4866	0.1076	183	58%	2300	20148000	4902	0.1872
IL	Joppa	887	6	2015	810991	2070	441	8445632	0.4901	0.1044	183	51%	2300	20148000	4938	0.2136
IL	Joppa	887	2	2015	871481	2131	502	8655055	0.4924	0.1161	183	54%	2300	20148000	4960	0.2360
															29628	

Combined MPS SO_2 Emissions at Max Heat Input (tons) **44378**

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 6

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 Tons	Max Group SO2 Rate	Max NOx Tons	Max Group NOx Rate	
IL	Baldwin	889	1	2017	4256973	1505	1593	38824663	0.0775	0.0821	625	78%	6439	56405640	2186	0.0775	2314	0.0821	
IL	Baldwin	889	2	2017	4248869	1618	1638	40385824	0.0801	0.0811	635	76%	5985	52428600	2100	0.0788	2127	0.0816	
IL	Baldwin	889	3	2017	0	0	0	0	0.0000	0.0000	635	0%	6400	56064000	2137	0.0779	2556	0.0849	**NOTE: 2016 Max SO2 Tons and Max NOx Tons**
IL	Havana	891	9	2017	2848787	1090	1240	30567133	0.0713	0.0811	488	67%	5518	48337680	1723	0.0764	1961	0.0840	
IL	Hennepin	892	1	2017	438327	1124	328	4508524	0.4984	0.1453	75	67%	802	7025520	1751	0.0899	510	0.0860	
IL	Hennepin	892	2	2017	1378893	3495	1030	14201402	0.4922	0.1451	231	68%	2518	22057680	5428	0.1265	1600	0.0914	
IL	Coffeen	861	1	2017	2149649	19	699	19939412	0.0019	0.0701	389	63%	3282	28750320	27	0.0019	1008	0.0701	
IL	Coffeen	861	2	2017	3960975	29	1783	39101271	0.0015	0.0912	617	73%	5544	48565440	36	0.0016	2214	0.0833	
IL	Duck Creek	6016	1	2017	2166840	25	1478	19985699	0.0025	0.1479	441	56%	5025	44019000	55	0.0019	3256	0.1068	
IL	ED Edwards	856	2	2017	1262936	2726	1318	13212705	0.4126	0.1996	281	51%	3321	29091960	6002	0.0814	2903	0.1247	
IL	ED Edwards	856	3	2017	2046863	3666	787	17698112	0.4142	0.0890	364	64%	4594	40243440	8335	0.1516	1790	0.1172	
IL	Joppa	887	1	2017	875026	2158	522	8983253	0.4804	0.1161	183	55%	2300	20148000	4839	0.1830	1170	0.1171	
IL	Joppa	887	2	2017	801348	1956	487	8140886	0.4804	0.1197	183	50%	2300	20148000	4840	0.2090	1206	0.1173	
IL	Joppa	887	3	2017	685802	1702	400	7034467	0.4839	0.1137	183	43%	2300	20148000	4875	0.2310	1146	0.1170	
IL	Joppa	887	4	2017	530810	1266	304	5244525	0.4826	0.1160	183	33%	2300	20148000	4862	0.2497	1168	0.1169	
IL	Joppa	887	5	2017	627033	1547	353	6357587	0.4868	0.1110	183	39%	2300	20148000	4904	0.2661	1118	0.1165	
IL	Joppa	887	6	2017	729089	1782	402	7292449	0.4888	0.1101	183	45%	2300	20148000	4924	0.2805	1109	0.1161	
IL	Newton	6017	1	2017	3546555	4873	1538	33298298	0.2927	0.0924	617	66%	7449	65253240	9550	0.2826	3014	0.1120	
					32554775	30578	15900	314776210	0.1943	0.1010	6496	57%							

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2017 SO2 Emissions	8830		128487546	0.137	Table 3
Dynegy Group 2017 SO2 Emissions Minus Baldwin 1, 3	7326		89662883	0.163	Table 4
Dynegy Group 2017 NOx Emissions		5829	128487546	0.091	Table 5
Dynegy Group 2017 NOx Emissions Minus Baldwin 1, 3		4236	89662883	0.094	Table 6
Old Ameren Group 2017 SO2 Emissions	21748		186288664	0.233	Table 7
Old Ameren Group 2017 NOx Emissions		10071	186288664	0.108	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		15325			Table 9
Dynegy Group NOx Emissions at Max Heat Input		11069			Table 11
Old Ameren NOx Emissions Max Heat Input		21103			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		29074	275951547	0.2107	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		14307	275951547	0.1037	Table 16

Table 10:

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
IL	Coffeen	861	2	2017	3960975	29	1783	39101271	0.0015	0.0912	617	73%	5544	48565440	36	0.0015
IL	Coffeen	861	1	2017	2149649	19	699	19939412	0.0019	0.0701	389	63%	3282	28750320	27	0.0016
IL	Duck Creek	6016	1	2017	2166840	25	1478	19985699	0.0025	0.1479	441	56%	5025	44019000	55	0.0019
IL	Newton	6017	1	2017	3546555	4873	1538	33298298	0.2927	0.0924	617	66%	7449	65253240	9550	0.1036
IL	ED Edwards	856	2	2017	1262936	2726	1318	13212705	0.4126	0.1996	281	51%	3321	29091960	6002	0.1453
IL	ED Edwards	856	3	2017	2046863	3666	787	17698112	0.4142	0.0890	364	64%	4594	40243440	8335	0.1876
IL	Joppa	887	1	2017	875026	2158	522	8983253	0.4804	0.1161	183	55%	2300	20148000	4839	0.2090
IL	Joppa	887	2	2017	801348	1956	487	8140886	0.4804	0.1197	183	50%	2300	20148000	4840	0.2272
IL	Joppa	887	4	2017	530810	1266	304	5244525	0.4826	0.1160	183	33%	2300	8592985	2073	0.2344
															35758	

Combined MPS SO2 Emissions at Max Heat Input **51083**

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 7

Question 14 - Updated Table 7 NOx

Plant	Unit	2002 Actual Heat Input (1000 mmBtu)	Base Year Emission Rate (Lbs/ mmBtu)	Base Year Emissions (Tons)	Current MPS Emission Rate (Lbs/ mmBtu)	Projected Emissions Under Current MPS Rate (Tons)	Tons/Year Reduction
Baldwin	1	43,884	0.55	12,119	0.1	2,194	9,925
Baldwin	2	37,135	0.4	7,405	0.1	1,857	5,548
Baldwin	3	46,403	0.12	2,850	0.1	2,386	464
Havana	9	28,514	0.27	3,901	0.1	1,477	2,424
Hennepin	1	4,684	0.32	760	0.1	245	515
Hennepin	2	17,575	0.33	2,862	0.1	841	2,021
Coffeen	1	18,570	0.53	4,918	0.11	1,018	3,900
Coffeen	2	37,545	0.5	9,422	0.11	2,101	7,321
Duck Creek	1	22,635	0.47	5,328	0.11	1,254	4,074
E D Edwards	2	17,222	0.45	3,901	0.11	973	2,928
E D Edwards	3	15,972	0.46	3,639	0.11	844	2,795
Joppa	1	13,548	0.13	876	0.11	741	135
Joppa	2	16,258	0.13	1,048	0.11	885	163
Joppa	3	15,396	0.13	1,030	0.11	876	154
Joppa	4	13,402	0.13	904	0.11	770	134
Joppa	5	15,094	0.12	939	0.11	864	75
Joppa	6	16,063	0.12	999	0.11	919	80
Newton	1	40,631	0.15	3,037	0.11	2,224	813
Total				65,938		22,469	43,469

Question 14 - Updated Table 8 SO2

Plant	Unit	2002 Actual Heat Input (1000 mmBtu)	Base Year Emission Rate (Lbs/ mmBtu)	Base Year Emissions (Tons)	Current MPS Emission Rate (Lbs/ mmBtu)	Projected Emissions Under Current MPS Rate (Tons)	Tons/Year Reduction
Baldwin	1	43,884	0.41	9,053	0.19	4,226	4,827
Baldwin	2	37,135	0.39	7,283	0.19	3,569	3,714
Baldwin	3	46,403	0.43	9,931	0.19	4,363	5,568
Havana	9	28,514	0.9	12,815	0.19	2,693	10,122
Hennepin	1	4,684	0.43	1,000	0.19	438	562
Hennepin	2	17,575	0.43	3,792	0.19	1,683	2,109
Coffeen	1	18,570	1.54	14,332	0.23	2,169	12,163
Coffeen	2	37,545	1.49	27,999	0.23	4,346	23,653
Duck Creek	1	22,635	0.97	11,026	0.23	2,651	8,375
E D Edwards	2	17,222	1.7	14,666	0.23	2,008	12,658
E D Edwards	3	15,972	1.21	9,683	0.23	1,857	7,826
Joppa	1	13,548	0.51	3,441	0.23	1,544	1,897
Joppa	2	16,258	0.51	4,139	0.23	1,863	2,276
Joppa	3	15,396	0.51	3,947	0.23	1,792	2,155
Joppa	4	13,402	0.52	3,488	0.23	1,545	1,943
Joppa	5	15,094	0.52	3,932	0.23	1,743	2,189
Joppa	6	16,063	0.52	4,182	0.23	1,853	2,329
Newton	1	40,631	0.45	9,046	0.23	4,577	4,469
Total				153,755		44,920	108,835

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 8

Bureau of Air Permit Section
File Organization Cover Sheet

Source Name:	Illinois Power Generating Co.
ID Number:	079 808 AAA
Application Number:	16 05 0017
Category:	03K
Item Date:	5-24-16

Submitted by C. Chambers

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397
BRUCE RAUNER, GOVERNOR LISA BONNETT, DIRECTOR

217/785-1705

CONSTRUCTION PERMIT

PERMITTEE

Illinois Power Generating Company
Attn: Rick Diericx
1500 Eastport Plaza Drive
Collinsville, Illinois 62234

Application No.: 16050017 I.D. No.: 079808AAA
Applicant's Designation: Date Received: May 11, 2016
Subject: Pilot Evaluation of Sorbent Injection
Date Issued: MAY 24 2016
Location: Newton Power Station, 6725 North 500th Street, Newton, Jasper County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT equipment for pilot evaluation of sorbent injection, as described in the above referenced application. This Permit is subject to standard conditions attached hereto and the following special condition(s):

1. Description

a. This permit addresses construction of equipment to conduct pilot evaluations of sorbent injection on one or both of the boiler(s) at this power generating facility. In these evaluations, a sorbent material will be pneumatically conveyed and injected into the combustion chamber, or "furnace," of a boiler or in to the ductwork between the economizer(s) and the electrostatic precipitator(s). Sorbent will be received and stored using portable equipment including storage silos with vent filters. The purpose of the project is to study the effectiveness of various sorbents in controlling the boiler's sulfur dioxide (SO_2) emissions.

b. For the purposes of this permit:

i. The boiler(s) on which an evaluation is conducted are referred to as the "affected boiler(s)".

ii. The portable equipment for receiving, storage and injection of sorbent, not including the piping to pneumatically convey sorbent to the affected boiler(s), is referred to as the "affected sorbent equipment".

2. Applicable Requirements

a. This permit does not relax or otherwise revise any requirements and conditions that apply to the operation, monitoring, recordkeeping and reporting for the affected boiler(s) as established in the Clean Air Act Permit Program (CAAPP) permit issued for the source, Permit No. 95090066, issued November 19, 2015.

b. The affected sorbent equipment is subject to and shall comply with applicable requirements of state emission standards for opacity and particulate matter (PM), including 35 IAC 212.123, 212.301 and 212.321.

c. This permit is issued based on minimal emissions of PM from the affected sorbent equipment, i.e., emissions of no more than 1.1 tons/year.

3. Non-Applicability Provisions

a. This permit is issued based on this project having a negligible effect on the emissions of affected boiler(s) for pollutants other than SO_2, given that it will only involve pilot evaluations of sorbent injection.

b. This permit is issued based on this project not constituting a modification of affected boiler(s) under the federal New Source Performance Standards, 40 CFR 60, as the project has the primary function of reducing emissions and therefore is not considered a modification pursuant to 40 CFR 60.14(e)(5).

c. This permit is issued based on the affected sorbent equipment not being subject to the NSPS for Nonmetallic Mineral Processing Plants, 40 CFR 60 Subpart OOO. This is because sorbents, such as powdered calcium carbonate, which are considered a "nonmetallic mineral" for purposes of this NSPS, handled by the affected sorbent equipment will not constitute a "nonmetallic mineral processing plant" as defined in 40 CFR 60.671 since sorbents will not be crushed or ground at this facility.

4. Operating Limitations

The duration of each evaluation of a different sorbent shall not exceed 1,000 hours, determined as the actual hours when sorbent is being injected into the affected boiler(s).

5. Recordkeeping Requirements

a. The Permittee shall maintain operating log(s) or records for the sorbent equipment that includes:

i. The identity of the process equipment, including name, model number, rated capacity, date first operated at the facility and the date last operated at the facility.

ii. The identity of the silo vent filter equipment, including name, model number, rated capacity (scfm) and design outlet dust loading.

iii. Inspection and maintenance logs for the sorbent equipment that list the activities performed, with date and description.

b. The Permittee shall keep records for each evaluation(s) conducted with affected sorbent equipment that, at a minimum, include:

i. The type of sorbent that is being used, the rate of injection of sorbent, the location(s) of sorbent injection and each period of time when an affected boiler was in operation with sorbent injection.

ii. Information collected addressing the effect of sorbent injection on the SO_2 emissions of the affected boiler(s).

iii. Information collected addressing the effect of sorbent injection on particulate emissions of the affected boiler(s).

iv. The duration of the evaluation (hours) and total amount of sorbent used in the evaluation (tons).

6. Reporting Requirements

a. The Permittee shall provide the Illinois EPA with the schedule for each evaluation conducted pursuant to this permit, including the identity of the affected boiler(s) on which the evaluation will be conducted and the dates when the boiler(s) may be operated with the sorbent. For this purpose, a copy of the schedule shall be submitted to the Illinois EPA's Regional Office in Collinsville.

b. If the Permittee prepares a formal report for an evaluation, which contains emissions data measured during the evaluations or describes the effect of the affected systems on emissions of SO_2, particulate or other pollutants from the boiler(s), the Permittee shall provide a copy of the report to the Illinois EPA.

c. The Permittee shall notify the Illinois EPA of deviations with the permit requirements within 30 days of an occurrence. Reports shall describe the deviation and the probable cause of such deviations, the corrective actions and preventive measures taken.

7. Mailing Addresses

Copies of required reports and notifications shall be sent to the Illinois EPA's Compliance Section at the following address unless otherwise indicated:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance Section (#40)
P.O. Box 19276
Springfield, Illinois 62794-9276

8. Authorization to Operate

a. Pursuant to this construction permit:

i. The Permittee may operate the affected sorbent equipment.

ii. The Permittee may operate the affected boiler(s) with sorbent injection as provided by this permit.

b. The authorization for operation provided above in Condition 8(a) will terminate when either pilot evaluations of sorbent injection is addressed in the CAAPP permit for the source or the Permittee notifies the Illinois EPA that no further pilot evaluations will be conducted pursuant to this permit.

c. These conditions supersede Standard Condition 6.

If you have any questions on this permit, please contact Daniel Rowell at 217/558-4368.

Raymond E. Pilapil
Acting Manager, Permit Section
Division of Air Pollution Control

REP:DBR:psj

DBR
5/24/16
JMS

STATE OF ILLINOIS
ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL
P. O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

July 1, 1985

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act, and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Agency and a supplemental written permit issued.

4. The Permittee shall allow any duly authorized agent of the Agency upon the presentation of credentials, at reasonable times:

   a. to enter the Permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

   b. to have access to and copy any records required to be kept under the terms and conditions of this permit,

   c. to inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

   d. to obtain and remove samples of any discharge or emission of pollutants, and

   e. to enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

   a. shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,

   b. does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities,

   c. does not release the Permittee from compliance with the other applicable statues and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations,

   d. does not take into consideration or attest to the structural stability of any units or parts of the project, and

e. in no manner implies or suggests that the Agency (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Agency before the equipment covered by this permit is placed into operation.

   b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Agency may file a complaint with the Board for modification, suspension or revocation of a permit:

   a. upon discovery that the permit application contained misrepresentations, misinformation or false statements or that all relevant facts were not disclosed, or

   b. upon finding that any standard or special conditions have been violated, or

   c. upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 9

Bureau of Air Permit Section

File Organization Cover Sheet

Source Name:	Illinois Power Generating Co Newton Power Station	
ID No.:	079808AAA	
Application No.:	16050017	
Category:	03K	
Item Date:	6/9/2017	
Keyword:	Choose an item.	*
Comment:		*
Part:	Choose an item. of Choose an item.	*

* If applicable

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397
BRUCE RAUNER, GOVERNOR   ALEC MESSINA, DIRECTOR

217/785-1705

CONSTRUCTION PERMIT - REVISED
NSPS SOURCE

PERMITTEE

Illinois Power Generating Company
Attn: Rick Diericx
1500 Eastport Plaza Drive
Collinsville, Illinois 62234

Application No.: 16050017   I.D. No.: 079808AAA
Applicant's Designation: Date Received: March 27, 2017
Subject: Dry Sorbent Injection
Date Issued: June 9, 2017
Location: Newton Power Station, 6725 North 500th Street, Newton, Jasper County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT equipment for sorbent injection, as described in the above referenced application. This Permit is subject to standard conditions attached hereto and the following special condition(s):

1. Description

a. This permit addresses construction of equipment to conduct pilot evaluations of sorbent injection on one or both of the coal-fired boiler(s). In these evaluations, a sorbent material will be pneumatically conveyed and injected into the combustion chamber, or "furnace," of a boiler or into the ductwork between the economizer(s) and the electrostatic precipitator(s). Sorbent will be received and stored using portable equipment including a storage silo with bin vent filter. The purpose of these evaluations is to study sorbents injection as a means of controlling the boiler(s) sulfur dioxide (SO_2) emissions.

b. This revised permit:

i. Allows ductwork sorbent injection with sodium bicarbonate, Trona or other sorbent to be conducted on an on-going basis on Boiler 1, no longer limiting the use of this equipment to evaluation of sorbent injection.

ii. Addresses use of a grinding mill to prepare sorbent for injection. Because sorbent is milled, certain sorbent handling equipment as well as this mill are now subject to the New Source Performance Standards (NSPS) for Nonmetallic Mineral Processing Plants, 40 CFR 60 Subpart OOO.

c. For the purposes of this revised permit:

i. Boiler 1 is referred to as the "affected boiler." This revised permit no longer addresses Boiler 2 because it has been permanently shut down.

ii. The equipment used to inject sorbent into the ductwork of the affected boiler is referred to as the "affected system."

iii. The equipment for receiving, storage and preparation, not including the affected system, is referred to as the "affected sorbent equipment".

2-1. Applicable Requirements for the Affected Boiler

Except as provided by Condition 2-2, this permit does not relax or revise applicability of requirements and conditions including operational, monitoring, recordkeeping and reporting requirements for the affected boiler as established in the Clean Air Act Permit Program (CAAPP) permit issued for the source, Permit No. 95090066, issued May 23, 2017.

2-2. Alternative Emission Standard for the Affected Boiler

Under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units, 40 CFR 63 Subpart UUUUU, as provided by 40 CFR 63.9991(c), when the Permittee operates the affected boiler with the affected system, the Permittee may use the applicable alternate SO_2 limit for existing coal-fired units in Table 2 of 40 CFR 63 Subpart UUUUU as the applicable criteria in 40 CFR 63.9991(c), as follows, would be met:

a. The boiler has a system using dry gas desulfurization technology, e.g., a DSI system, and an SO_2 continuous emissions monitoring system (CEMS) is installed [40 CFR 63.9991(c)(1)]; and

b. At all times, the dry gas desulfurization technology and SO_2 CEMS are operated consistent with 40 CFR 63.10000(b). [40 CFR 63.9991(c)(2)]

Note: Dry sorbent injection is a type of "dry flue gas desulfurization technology," as defined by 40 CFR 63.10042.

2-3. Required Work Practices for the Sorbent Injection System

If the Permittee operates the affected system as an "applicable control device" for purposes of 40 CFR 63 Subpart UUUUU (i.e., the affected system is operated during periodic performance testing for emissions of hydrogen chloride pursuant to 40 CFR 63 Subpart UUUUU or the Permittee is complying with the alternate limit for SO_2 emissions), the Permittee must, at all times, operate and maintain the affected system and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions pursuant to 40 CFR 63.10000(b).

2-4. Applicable Federal Emission Standards for the Affected Sorbent Equipment

The grinding mill and storage silo are subject to the New Source Performance Standards (NSPS) for Nonmetallic Mineral Processing, 40 CFR 60 Subpart OOO, and the applicable requirements of the General Provisions of the NSPS, 40 CFR 60 Subpart A.

a. Pursuant to 40 CFR 60.672(b) and Table 3 of 40 CFR 60 Subpart OOO, "fugitive emissions" of PM, as defined in 40 CFR 60.671, from the storage silo and grinding mill shall not exceed 7 percent opacity.

b. Pursuant to 40 CFR 60.672(f) and Table 2 of 40 CFR 60 Subpart OOO, the opacity of emissions from the storage silos shall not exceed 7 percent.

c. Pursuant to 40 CFR 60.11(d), at all times, the Permittee shall maintain and operate these units, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.

2-5. Applicable State Emission Standards for the Affected Sorbent Equipment

The affected sorbent equipment is subject to the following rules for opacity, visible emissions and particulate:

a. 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent into the atmosphere from any emission unit.

b. 35 IAC 212.301 and 212.314, which provide that no person shall cause or allow the emission of fugitive particulate matter from any emission unit, that is visible by an observer looking generally toward the zenith (i.e., looking at the sky directly overhead) from a point beyond the property line of the source, except when the wind speed is greater than 25 mph (40.2 km/h).

c. 35 IAC 212.321(a), which provides that no person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any new process emission unit which, either alone or in combination with the emission of particulate matter from all other new similar process emission units at a source or premises, exceeds the allowable emission rates specified in 35 IAC 212.321(c).

3. Nonapplicability Provisions

a. This permit is issued based on this project not being a major project for purposes of the federal rules for Prevention of Significant Deterioration, 40 CFR 52.21.

i. For SO_2, this is because this project is an emissions control project whose purpose is to reduce emissions of SO_2 from the affected boiler.

ii. For emissions of CO and NO_x, the Permittee has projected that this project will not increase emissions of these pollutants.

iii. For emissions particulate matter:

A. From the affected boiler, this is because the Permittee has projected decreases in emissions of the affected boiler with this project.

B. From the affected sorbent equipment, this is because the increases in emissions are not significant. (See Condition 4(b))

C. For plant roadways, this is because the increased vehicle traffic on plant roadways for transport of sorbents and disposal of additional fly ash generated by the affected boiler will not result in a significant increase in emissions.

b. This permit is issued based on the changes made to the affected boiler not constituting a modification of the boiler under the federal New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60 Subpart Da, or the NSPS for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT, as the changes have the primary function of reducing emissions and therefore is not considered a modification pursuant to 40 CFR 60.14(e)(5). Accordingly, this project does not trigger applicability of requirements of 40 CFR 60 Subpart Da for units modified after May 3, 2011. It also does not trigger applicable requirements of 40 CFR 60 Subpart TTTT for units modified after June 18, 2014.

c. This permit is issued based on the affected sorbent equipment not being subject to a PM emission limit under 40 CFR 60 Subpart OOO:

i. For the grinding mill, this is because this mill will not have any "stack emissions," as defined by 40 CFR 60.671, since this mill feeds ground material directly into the affected boiler and does not have a vent to the atmosphere.

ii. For the storage silo, this is because it will continue to be controlled by its own filter device and because 40 CFR 60.672(f) provides that any baghouse that controls emissions from only an individual, enclosed storage bin is exempt from the applicable PM limit and must instead meet an opacity limit of 7 percent.

4. <u>Operational and Emission Limits</u>

a. i. The amount of sorbent material injected into the affected boiler shall not exceed 4,400 tons/month and 43,800 tons/year.

ii. Compliance with the above annual limit and other annual limits set by this permit shall be determined from the sum of the data for the current month plus the preceding 11 months (running 12 month total)

b. i. Emissions of PM from sorbent grinding mill shall not exceed 0.26 pounds/hour and 1.2 tons/year.

ii. This permit is issued based on negligible emissions of PM from the storage silo and pneumatic conveyors, i.e., emissions of no more than 0.1 pounds/hour and 0.44 tons/year.

c. At all times, the Permittee shall operate and maintain the affected sorbent equipment and associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

5-1. NSPS Performance Testing

a. For the grinding mill and storage silo, the Permittee shall comply with the requirements of the NSPS for performance testing, including the following, unless USEPA waives such testing or approves an alternative method pursuant to 40 CFR 60.8(b).

b. The timing of performance testing for opacity of fugitive emissions shall be as follows. These performance tests shall be conducted in accordance with 40 CFR 60.11 and 60.675(b), (c) and (e).

i. Pursuant to 40 CFR 60.8 and 60.675(a), an initial performance test shall be conducted within 60 days after each of the unit achieves its maximum operating rate, but not later than 180 days after initial startup. Unless otherwise specified by the Illinois EPA, this test shall be conducted during conditions that are representative of the maximum operating rate of the unit.

ii. Pursuant to Table 3 of 40 CFR 60 Subpart OOO, performance tests must subsequently be conducted within 5 years from the previous test.

iii. Performance tests shall also be conducted upon written request from the Illinois EPA, for a unit as specified in such request. For this purpose, tests shall be conducted within 30 days of the request from the Illinois EPA or such later date agreed to by the Illinois EPA.

c. i. Pursuant to 40 CFR 60.8(d) and Table 1 of 40 CFR 60 Subpart OOO, the Illinois EPA shall be notified prior to these performance tests to enable the Illinois EPA to have an observer present. The Illinois EPA may, at its discretion, accept notification with shorter advance notice provided that the Illinois EPA will not accept such notifications if it interferes with the Illinois EPA's ability to be present during these tests.

ii. For opacity observations, notification of the expected date of the observations shall be submitted a minimum of 7 days prior to the expected date. Notification of the actual date and expected time of the observations shall be submitted a minimum of five working days prior to the actual date of the observations.

d. Pursuant to 40 CFR 60.676(f), the Permittee shall submit reports for these tests to the Illinois EPA, which reports shall include both the results of the test and documentation for the test.

5-2. Opacity Observations

Within 60 days of a written request by the Illinois EPA, or such later date agreed to by the Illinois EPA, the Permittee shall conduct opacity observations for specific sorbent equipment in accordance with USEPA Method 9.

5-3. Emission Testing for the Affected Boiler

a. By September 30, 2018 (i.e., approximately 14 months after the initial startup of the affected boiler with the affected system), unless the Permittee has discontinued sorbent injection, the Permittee shall have the PM emissions of the boiler measured by a qualified testing service while the boiler is operating in the maximum load range and other representative operating conditions. USEPA Method 5 shall be used for this testing, unless another method is approved by the Illinois EPA.

b. Prior to carrying out these tests, the Illinois EPA's Regional Office and Source Emission Test Specialist shall be notified a minimum of 30 days prior to the expected date of these tests and further notified a minimum of 5 working days prior to the tests of the exact date, time and place of these tests, to enable the Agency to witness these tests.

c. The Final Report(s) for these tests shall be submitted to the Illinois EPA within 60 days after the date of testing. The following information shall be submitted with the results:

i. The firing rate of the affected boiler during each test run (million Btu/hr).

ii. The gross power generation rate for the electrical generator during the test.

iii. The type of sorbent and sorbent injection rate(s), as measured during the tests.

iv. The opacity monitored during each test run (6-minute averages and hourly averages).

d. Within 120 days after the date of testing, the Permittee shall submit a review of the implications of the results of the testing for the Compliance Assurance Monitoring (CAM) Plan for the affected boiler, as addressed by Condition 7.1.13-1 of the CAAPP permit for the source. For this purpose, the Permittee shall evaluate the effect of sorbent injection on PM emissions and opacity of the affected boiler and determine whether the indicator value for opacity still adequately addresses compliance with the PM emission standards that apply to the boiler.

Note: If the Permittee seeks to revise the CAM Plan for the affected boiler, the Permittee must submit its proposed revised CAM Plan to the Illinois EPA as part of an application for a significant modification of the CAAPP permit for the source, Permit 95090066.

6. Instrumentation

The Permittee shall install, operate, and maintain instrumentation for the operation of the affected system. For this purpose, operation of the affected system may be monitored either directly (e.g., in terms of the sorbent injection rate by mass or volume) or indirectly (e.g., in terms of the amperage of the electric motor for the sorbent feed equipment, the setting for the sorbent injection rate or the setting for the rate of sorbent injection relative to boiler load).

7. Inspection Requirements

a. i. Inspections of the affected sorbent equipment, including emission control measures, shall be conducted at least once per month when material is being handled to confirm proper operation as related to control of emissions.

ii. The Permittee shall maintain records of the above activities. These records shall include the date that inspections were conducted, with description of the inspection.

b. For the grinding mill and silo, the Permittee shall conduct either periodic inspections for visible emissions in accordance with 40 CFR 60.674(d) or install, operate and maintain a bag leak detector system in accordance with 40 CFR 60.674(e) and 60.676(b).

8. Recordkeeping Requirements

a. For the grinding mill and silo, the Permittee shall comply with the applicable recordkeeping requirements of the NSPS, including 40 CFR 60.7 and 60.676.

b. The Permittee shall maintain records for the following items for the grinding mill:

i. A file containing a determination of the maximum PM emission rates of the grinding mill in pounds/hour and pounds/ton of sorbent handled, overall for the combination of all units, with supporting documentation and calculations.

ii. Records for the total amount of sorbent material handled, by type (tons/month and tons/year).

iii. Records of emissions of PM from the grinding mill (tons/month and tons/year).

c. The Permittee shall maintain records for maintenance/repair activities for the control equipment associated with the affected sorbent equipment that include the date and description of the maintenance/repair activities.

d. The Permittee shall maintain records of the following items related to the purchase of sorbents for the affected system:

i. Annual taxes paid on sorbents; and

ii. Invoices or receipts detailing each shipment of sorbent received.

e. Unless otherwise provided by the NSPS, all records required by this permit shall be retained at a readily accessible location for at least five years from the date of entry and shall be made available for inspection and copying by the Illinois EPA upon request.

9. Notification Requirements

a. For the grinding mill and silo, the Permittee shall submit notifications in accordance with the NSPS, including 40 CFR 60.7.

b. The Permittee shall notify the Illinois EPA in advance of using sorbent(s) other than sodium bicarbonate or Trona in the affected system. This notification shall be submitted at least two months in advance if possible or otherwise promptly after the Permittee learns that an alternative sorbent will need to be used. This notification shall identify the alternative sorbent and include an explanation of the reason for use of an alternate sorbent, the expected duration for use of the alternative sorbent (if temporary) and the expected changes in sorbent injection rates.

10. Reporting Requirements

a. With the Annual Emission Report required by 35 IAC Part 254, the Permittee shall report:

i. The amount of sorbent injected into the affected boiler by the affected system (tons/year).

ii. The total annual sales taxes paid by the Permittee on sorbents, as addressed by the records required by Condition 8(e)(i).

b. The Permittee shall notify the Illinois EPA of deviations from the requirements of this permit within 30 days of such occurrence. Reports shall describe the deviation, the probable cause of such deviation, the corrective actions taken, and any preventive measures taken. If a deviation is addressed by reporting requirements under applicable rules, this requirement may be satisfied with the reporting required by such rules.

11. Mailing Addresses

a. Copies of required reports and notifications shall be sent to the Illinois EPA's Compliance Section at the following address unless otherwise indicated:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance Section (#40)
P.O. Box 19276
Springfield, Illinois 62794-9276

b. One copy of notifications and reports required by this permit that concern emission testing and monitoring shall also be sent electronically to the Illinois EPA, Bureau of Air, Compliance Section, Source Monitoring Unit, using the State of Illinois's File Transfer Website, unless otherwise instructed by the Illinois EPA:

http://filet.illinois.gov

Recipient Email Address: EPA.BOA.SMU@illinois.gov
File Transfer Email Subject: Newton Power Station, ID 079808AAA
Message to Recipient: "A description of the submittal, with date"

12. Authorization to Operate

Pursuant to this construction permit, the Permittee may operate the affected sorbent equipment and the affected boiler with the affected system provided that the Permittee submits a timely and complete application for modification to the CAAPP permit for the source to address this project. This condition supersedes Standard Condition 6.

Please note that this permit has been revised at the request of the Permittee to address use of the affected system with Boiler 1 on an ongoing basis and the addition of a sorbent grinding mill to prepare sorbent for the affected sorbent equipment. As a consequence, this revised permit addresses applicable emission standards and related requirements for the affected sorbent equipment under the NSPS, 40 CFR 60 Subpart OOO. It also addresses the use of sorbent injection for Boiler 1 under 40 CFR 63 Subpart UUUUU.

If you have any questions on this permit, please contact Daniel Rowell at 217/558-4368.

Raymond E Pilapil

Raymond E. Pilapil
Manager, Permit Section
Division of Air Pollution Control

REP:DBR:lsm
6/9/17

STATE OF ILLINOIS
ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL
P. O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

July 1, 1985

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act, and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Agency and a supplemental written permit issued.

4. The Permittee shall allow any duly authorized agent of the Agency upon the presentation of credentials, at reasonable times:

    a. to enter the Permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

    b. to have access to and copy any records required to be kept under the terms and conditions of this permit,

    c. to inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

    d. to obtain and remove samples of any discharge or emission of pollutants, and

    e. to enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

    a. shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,

    b. does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities,

    c. does not release the Permittee from compliance with the other applicable statues and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations,

    d. does not take into consideration or attest to the structural stability of any units or parts of the project, and

e. in no manner implies or suggests that the Agency (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Agency before the equipment covered by this permit is placed into operation.

   b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Agency may file a complaint with the Board for modification, suspension or revocation of a permit:

   a. upon discovery that the permit application contained misrepresentations, misinformation or false statements or that all relevant facts were not disclosed, or

   b. upon finding that any standard or special conditions have been violated, or

   c. upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO 35 ILL. ADM.	)	(Rulemaking-Air)
CODE 225.233, MULTI-POLLUTANT	)	
STANDARDS	)	

PRE-FILED TESTIMONY OF ANDREW ARMSTRONG
ON BEHALF OF THE ILLINOIS ATTORNEY GENERAL'S OFFICE

ATTACHMENT 10

State	Facility Name	Facility ID (ORISPL)	Unit ID	SO2 (tons)	NOx (tons)	2002 Heat Input (mmBtu)	2017 SO2 Rate (lb/mmBtu)	2017 NOx Rate (lb/mmBtu)	
IL	Baldwin	889	1	1701	1801	43884000	0.0775	0.0821	
IL	Baldwin	889	2	1487	1506	37135000	0.0801	0.0811	
IL	Baldwin	889	3	1768	2116	46403000	0.0762	0.0912	**NOTE: 2016 SO2 Rate and NOx Rate**
IL	Havana	891	9	1017	1156	28514000	0.0713	0.0811	
IL	Hennepin	892	1	1167	340	4684000	0.4984	0.1453	
IL	Hennepin	892	2	4325	1275	17575000	0.4922	0.1451	
IL	Coffeen	861	1	18	651	18570000	0.0019	0.0701	
IL	Coffeen	861	2	28	1712	37545000	0.0015	0.0912	
IL	Duck Creek	6016	1	28	1674	22635000	0.0025	0.1479	
IL	ED Edwards	856	2	3553	1719	17222000	0.4126	0.1996	
IL	ED Edwards	856	3	3308	711	15972000	0.4142	0.0890	
IL	Joppa	887	1	3254	786	13548000	0.4804	0.1161	
IL	Joppa	887	2	3905	973	16258000	0.4804	0.1197	
IL	Joppa	887	3	3725	875	15396000	0.4839	0.1137	
IL	Joppa	887	4	3234	777	13402000	0.4826	0.1160	
IL	Joppa	887	5	3674	838	15094000	0.4868	0.1110	
IL	Joppa	887	6	3926	884	16063000	0.4888	0.1101	
IL	Newton	6017	1	5946	1877	40631000	0.2927	0.0924	
				46064	21672	420531000	0.2191	0.1031	

	Tons	Tons	Heat Input	Rate	
Dynegy Group SO2 Emissions	11465		178195000	0.129	Table 3
Dynegy Group NOx Emissions		8195	178195000	0.092	Table 5
Old Ameren Group SO2 Emissions	34599		242336000	0.286	Table 7
Old Ameren Group NOx Emissions		13478	242336000	0.111	Table 8
COMBINED	**46064**	**21672**	**420531000**		

Table 10:

State	Facility Name	Facility ID (ORISPL)	Unit ID	SO2 (tons)	Heat Input (MMBtu)	Unit SO2 Rate	Group SO2 Rate	Unit NO2 Rate	NOx (tons)
IL	Coffeen	861	2	28	37545000	0.0015	0.0015	0.0912	1712
IL	Coffeen	861	1	18	18570000	0.0019	0.0016	0.0701	651
IL	Duck Creek	6016	1	28	22635000	0.0025	0.0019	0.1479	1674
IL	Newton	6017	1	5946	40631000	0.2927	0.1009	0.0924	1877

IL	ED Edwards	856	2	3553	17222000	0.4126	0.1402	0.1996	1719
IL	ED Edwards	856	3	3308	15972000	0.4142	0.1688	0.0890	711
IL	Joppa	887	1	3254	13548000	0.4804	0.1943	0.1161	786
IL	Joppa	887	2	3905	16258000	0.4804	0.2198	0.1197	973
IL	Joppa	887	4	2589	10728292	0.4826	0.2344	0.1160	622
	OLD AMEREN			**22629**	**193109292**				**10725**
	DYNEGY			**11465**	**178195000**				**8195**
	COMBINED			**34094**	**371304292**				**18920**

Exhibit 1 - MPS Units Capacity Factors (AG Response Questions Raised First Hearing Filed 2/16/18)

Facility Name	Unit ID	2017 Gross Load (MW-h)	2016 Gross Load (MW-h)	2015 Gross Load (MW-h)	2014 Gross Load (MW-h)	2013 Gross Load (MW-h)	2012 Gross Load (MW-h)	2011 Gross Load (MW-h)	2010 Gross Load (MW-h)	2009 Gross Load (MW-h)	2008 Gross Load (MW-h)	Nameplate Capacity (MW)	2017 Capacity Factor	2016 Capacity Factor	2015 Capacity Factor	2014 Capacity Factor	20 Ca Fa
Baldwin	1	4256973	3579945	3929009	3612677	4353264	4382095	4256142	4922426	4719810	4365766	625	78%	65%	72%	66%	
Baldwin	2	4248869	4142070	3016142	4529481	4977489	4063944	4872441	5076725	3740462	4874545	635	76%	74%	54%	81%	
Baldwin	3	0	2907612	4220738	4531695	4211091	4794276	5232122	3547576	4500586	4634595	635	0%	52%	76%	81%	
Coffeen	1	2149649	1645863	1663873	2151742	1821705	1945318	2286431	2300356	1586382	2415664	389	63%	48%	49%	63%	
Coffeen	2	3960975	3436013	3324374	3635208	3333747	3620176	3213509	3073162	2948670	3515473	617	73%	64%	62%	67%	
Duck Creek	1	2166840	2338467	2363610	2477495	2766167	3075539	2327215	2827797	2137973	2482081	441	56%	61%	61%	64%	
E D Edwards	2	1262963	1089069	1698538	1854000	1838296	1879308	1916844	1818425	1878918	1565992	281	51%	44%	69%	75%	
E D Edwards	3	2046863	1938365	1475139	2111602	2302982	1937026	2332239	2446622	2390773	2187691	364	64%	61%	46%	66%	
Havana	9	2848787	2671713	2115992	2850484	3153270	3023729	3290873	3356096	2280409	3060557	488	67%	62%	49%	67%	
Hennepin	1	438327	416864	439325	459685	359877	515218	577749	573819	533447	397677	75	67%	63%	67%	70%	
Hennepin	2	1378893	1158049	1246904	1379725	1411586	1808108	1804087	1868434	1775299	1339958	231	68%	57%	62%	68%	
Joppa	1	875026	752282	956900	1312296	1292822	1260495	1418830	1456298	1424827	1151113	183	55%	47%	60%	82%	
Joppa	2	801348	736600	871481	1320187	1256764	1233258	1194562	1397275	1318607	1516512	183	50%	46%	54%	82%	
Joppa	3	685802	428451	840144	1247131	1186607	1102056	1361558	1341577	1365346	1497672	183	43%	27%	52%	78%	
Joppa	4	530810	682622	921854	1333425	1267827	1225340	1437495	1439559	847003	1478670	183	33%	43%	58%	83%	
Joppa	5	627033	382421	930759	1191697	1231189	1027743	1416709	1373654	1324612	1485316	183	39%	24%	58%	74%	
Joppa	6	729089	476243	810991	1317637	1215881	1151848	1444091	1407797	1346374	1504067	183	45%	30%	51%	82%	
Newton	1	3546555	2348892	2842906	3490220	3336394	3637379	3964715	4200305	4374462	4386205	617	66%	43%	53%	65%	
TOTAL		32554802	31131541	33668679	40806386	41316958	41682856	44347613	44427903	40493961	43859554	6496	57%	55%	59%	72%	

Exhibit 1 - MPS Units Capacity Factors (AG Response Questions Raised First Hearing Filed 2/16/18)

Facility Name	Unit ID	2017 Gross Load (MW-h)	2016 Gross Load (MW-h)	2015 Gross Load (MW-h)	2014 Gross Load (MW-h)	2013 Gross Load (MW-h)	2012 Gross Load (MW-h)	2011 Gross Load (MW-h)	2010 Gross Load (MW-h)	2009 Gross Load (MW-h)	2008 Gross Load (MW-h)	Nameplate Capacity (MW)	2017 Capacity Factor	2016 Capacity Factor	2015 Capacity Factor	2014 Capacity Factor
Baldwin	1	4256973	3579945	3929009	3612677	4353264	4382095	4256142	4922426	4719810	4365766	625	78%	65%	72%	66%
Baldwin	2	4248869	4142070	3016142	4529481	4977489	4063944	4872441	5076725	3740462	4874545	635	76%	74%	54%	81%
Baldwin	3	0	2907612	4220738	4531695	4211091	4794276	5232122	3547576	4500586	4634595	635	0%	52%	76%	81%
Coffeen	1	2149649	1645863	1663873	2151742	1821705	1945318	2286431	2300356	1586382	2415664	389	63%	48%	49%	63%
Coffeen	2	3960975	3436013	3324374	3635208	3333747	3620176	3213509	3073162	2948670	3515473	617	73%	64%	62%	67%
Duck Creek	1	2166840	2338467	2363610	2477495	2766167	3075539	2327215	2827797	2137973	2482081	441	56%	61%	61%	64%
E D Edwards	2	1262963	1089069	1698538	1854000	1838296	1879308	1916844	1818425	1878918	1565992	281	51%	44%	69%	75%
E D Edwards	3	2046863	1938365	1475139	2111602	2302982	1937026	2332239	2446622	2390773	2187691	364	64%	61%	46%	66%
Havana	9	2848787	2671713	2115992	2850484	3153270	3023729	3290873	3356096	2280409	3060557	488	67%	62%	49%	67%
Hennepin	1	438327	416864	439325	459685	359877	515218	577749	573819	533447	397677	75	67%	63%	67%	70%
Hennepin	2	1378893	1158049	1246904	1379725	1411586	1808108	1804087	1868434	1775299	1339958	231	68%	57%	62%	68%
Joppa	1	875026	752282	956900	1312296	1292822	1260495	1418830	1456298	1424827	1151113	183	55%	47%	60%	82%
Joppa	2	801348	736600	871481	1320187	1256764	1233258	1194562	1397275	1318607	1516512	183	50%	46%	54%	82%
Joppa	3	685802	428451	840144	1247131	1186607	1102056	1361558	1341577	1365346	1497672	183	43%	27%	52%	78%
Joppa	4	530810	682622	921854	1333425	1267827	1225340	1437495	1439559	847003	1478670	183	33%	43%	58%	83%
Joppa	5	627033	382421	930759	1191697	1231189	1027743	1416709	1373654	1324612	1485316	183	39%	24%	58%	74%
Joppa	6	729089	476243	810991	1317637	1215881	1151848	1444091	1407797	1346374	1504067	183	45%	30%	51%	82%
Newton	1	3546555	2348892	2842906	3490220	3336394	3637379	3964715	4200305	4374462	4386205	617	66%	43%	53%	65%
TOTAL		32554802	31131541	33668679	40806386	41316958	41682856	44347613	44427903	40493961	43859554	6496	57%	55%	59%	72%

		2017 Heat Input (mmBtu)	2016 Heat Input (mmBtu)	2015 Heat Input (mmBtu)	2014 Heat Input (mmBtu)	2013 Heat Input (mmBtu)	2012 Heat Input (mmBtu)	2011 Heat Input (mmBtu)	2010 Heat Input (mmBtu)	2009 Heat Input (mmBtu)	2008 Heat Input (mmBtu)
DYNEGY GROUP											
Baldwin	1	38824663	32659083	37866256	32456229	39629830	43725328	37783602	42860896	42376555	38900401
Baldwin	2	40385824	38830110	28230422	42613958	46281964	38467310	45092055	46480909	34951998	47395103
Baldwin	3	0	30643341	42135390	44089201	41921039	48467691	50791868	34012081	43656835	44255109
Havana	9	30567133	30279146	23344525	31583549	34312338	32957602	36833553	35225775	22274295	30758032
Hennepin	1	4508524	4417514	4601595	4720259	3662676	5255799	5907566	5916688	5566820	4277351
Hennepin	2	14201402	12095937	12788515	14008763	13966816	18303983	18309065	19085795	18278934	13264585
TOTAL		**128487546**	**148925131**	**148966703**	**169471959**	**179774663**	**187177713**	**194717709**	**183582144**	**167105437**	**178850581**
MPS SO2 (tons)		**12206**	**14148**	**14152**	**16100**	**17079**	**17782**	**18498**	**17440**	**15875**	**16991**
MPS NOx (tons)		**6424**	**7446**	**7448**	**8474**	**8989**	**9359**	**9736**	**9179**	**8355**	**8943**

OLD AMEREN GROUP											
Coffeen	1	19939412	15328145	15993139	20571870	18461732	19425263	23901997	24410806	17549206	26759121
Coffeen	2	39101271	33234005	33529517	35557130	32217458	34734221	33598366	32608370	30016843	38553048
Duck Creek	1	19985699	23470382	22722935	22385698	23561779	25219962	24159532	28849323	21407745	23856295
E D Edwards	2	13212705	10948007	16917465	18609882	18193244	17880205	20921358	17992114	19069150	16796596
E D Edwards	3	17698112	17244294	13527349	20704034	22552954	18872502	25293516	26068920	24994709	24449330
Joppa	1	8983253	7703571	9580656	12635915	12547946	12687192	14397390	14851874	14380768	11899023

Exhibit 1 - MPS Units Capacity Factors (AG Response Questions Raised First Hearing Filed 2/16/18)

5055	12687892	12120069	12343639	11839036	14204176	13239471	15860012
3510	12153206	11530620	11223231	13628892	13382030	13958821	14928537
8359	12939835	12272250	12426971	14356229	14331786	8451146	14682159
1988	11893458	12289122	10838724	14674513	14188501	13595175	15084592
5632	13094796	12069593	12063815	14927835	14506686	13689006	15179949
8355	32214778	31216532	35688037	39488197	42601247	43565338	42347365
3960	**225448494**	**219033299**	**223403762**	**251186861**	**257995833**	**233917378**	**260396027**
1141	**25927**	**25189**	**25691**	**28886**	**29670**	**26900**	**29946**
0111	**12400**	**12047**	**12287**	**13815**	**14190**	**12865**	**14322**

0663	**394920453**	**398807962**	**410581475**	**445904570**	**441577977**	**401022815**	**439246608**
5293	**42026**	**42267**	**43473**	**47385**	**47110**	**42776**	**46936**
7559	**20873**	**21036**	**21646**	**23551**	**23369**	**21221**	**23264**

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons
IL	Baldwin	889	1	2013	4353264	1513	1388	39629830	0.0764	0.0701	625	80%	6439	56405640	2154
IL	Baldwin	889	2	2013	4977489	1714	1670	46281964	0.0741	0.0722	635	89%	5985	52428600	1942
IL	Baldwin	889	3	2013	4211091	1576	1902	41921039	0.0752	0.0907	635	76%	6400	56064000	2108
IL	Havana	891	9	2013	3153270	1130	1336	34312338	0.0659	0.0779	488	74%	5518	48337680	1592
IL	Hennepin	892	1	2013	359877	883	259	3662676	0.4821	0.1413	75	55%	802	7025520	1694
IL	Hennepin	892	2	2013	1411586	3396	989	13966816	0.4863	0.1417	231	70%	2518	22057680	5364
IL	Coffeen	861	1	2013	1821705	61	635	18461732	0.0066	0.0688	389	53%	3282	28750320	95
IL	Coffeen	861	2	2013	3333747	47	1251	32217458	0.0029	0.0776	617	62%	5544	48565440	71
IL	Duck Creek	6016	1	2013	2766167	231	1268	23561779	0.0196	0.1076	441	72%	5025	44019000	431
IL	ED Edwards	856	2	2013	1838296	4107	1752	18193244	0.4515	0.1926	281	75%	3321	29091960	6568
IL	ED Edwards	856	3	2013	2302982	4852	777	22552954	0.4303	0.0689	364	72%	4594	40243440	8658
IL	Joppa	887	1	2013	1292822	2843	730	12547946	0.4532	0.1164	183	81%	2300	20148000	4565
IL	Joppa	887	2	2013	1256764	2741	711	12120069	0.4523	0.1173	183	78%	2300	20148000	4557
IL	Joppa	887	3	2013	1186607	2622	614	11530620	0.4549	0.1066	183	74%	2300	20148000	4582
IL	Joppa	887	4	2013	1267827	2783	657	12272250	0.4535	0.1071	183	79%	2300	20148000	4569
IL	Joppa	887	5	2013	1231189	2802	670	12289122	0.4560	0.1091	183	77%	2300	20148000	4594
IL	Joppa	887	6	2013	1215881	2751	657	12069593	0.4559	0.1089	183	76%	2300	20148000	4593
IL	Newton	6017	1	2013	3336394	7270	1583	31216532	0.4658	0.1014	617	62%	7449	65253240	15196
					41316958	43324	18849	398807962	0.2173	0.0945	6496	73%			

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2013 SO2 Emissions	10213		179774663	0.114	Table 3
Dynegy Group 2013 SO2 Emissions Minus Baldwin 1, 3	7123		98223794	0.145	Table 4
Dynegy Group 2013 NOx Emissions		7545	179774663	0.084	Table 5
Dynegy Group 2013 NOx Emissions Minus Baldwin 1, 3		4255	98223794	0.087	Table 6
Old Ameren Group 2013 SO2 Emissions	33111		219033299	0.302	Table 7
Old Ameren Group 2013 NOx Emissions		11305	219033299	0.103	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		14853			Table 9
Dynegy Group NOx Emissions at Max Heat Input		10353			Table 11
Old Ameren NOx Emissions Max Heat Input		19441			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		40235	317257093	0.2536	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		15559	317257093	0.0981	Table 16

Attach 3
4/3/2018 Testim

r	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
13	3333747	47	1251	32217458	0.0029	0.0776	617	62%	5544	48565440	71	0.0029
13	1821705	61	635	18461732	0.0066	0.0688	389	53%	3282	28750320	95	0.0043
13	2766167	231	1268	23561779	0.0196	0.1076	441	72%	5025	44019000	431	0.0099
13	2302982	4852	777	22552954	0.4303	0.0689	364	72%	4594	40243440	8658	0.1146
13	1838296	4107	1752	18193244	0.4515	0.1926	281	75%	3321	29091960	6568	0.1660
13	1256764	2741	711	12120069	0.4523	0.1173	183	78%	2300	20148000	4557	0.1933
13	1292822	2843	730	12547946	0.4532	0.1164	183	81%	2300	20148000	4565	0.2160
13	1267827	2783	657	12272250	0.4535	0.1071	183	79%	2300	20148000	4569	0.2351
											29515	

nput (tons) **44367**

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons	Ma Gr SO
IL	Baldwin	889	1	2014	3612677	1213	1188	32456229	0.0748	0.0732	625	66%	6439	56405640	2109	
IL	Baldwin	889	2	2014	4529481	1490	1475	42613958	0.0699	0.0692	635	81%	5985	52428600	1834	
IL	Baldwin	889	3	2014	4531695	1706	2040	44089201	0.0774	0.0926	635	81%	6400	56064000	2169	
IL	Havana	891	9	2014	2850484	1068	1181	31583549	0.0676	0.0748	488	67%	5518	48337680	1635	
IL	Hennepin	892	1	2014	459685	1002	347	4720259	0.4246	0.1470	75	70%	802	7025520	1492	
IL	Hennepin	892	2	2014	1379725	2959	1019	14008763	0.4224	0.1455	231	68%	2518	22057680	4659	
IL	Coffeen	861	1	2014	2151742	22	656	20571870	0.0022	0.0638	389	63%	3282	28750320	31	
IL	Coffeen	861	2	2014	3635208	10	1223	35557130	0.0006	0.0688	617	67%	5544	48565440	13	
IL	Duck Creek	6016	1	2014	2477495	240	1065	22385698	0.0214	0.0952	441	64%	5025	44019000	472	
IL	ED Edwards	856	2	2014	1854000	4021	1723	18609882	0.4321	0.1851	281	75%	3321	29091960	6286	
IL	ED Edwards	856	3	2014	2111602	4244	704	20704034	0.4100	0.0680	364	66%	4594	40243440	8249	
IL	Joppa	887	1	2014	1312296	3080	701	12635915	0.4875	0.1109	183	82%	2300	20148000	4911	
IL	Joppa	887	2	2014	1320187	3093	710	12687892	0.4876	0.1119	183	82%	2300	20148000	4912	
IL	Joppa	887	3	2014	1247131	2950	654	12153206	0.4855	0.1077	183	78%	2300	20148000	4891	
IL	Joppa	887	4	2014	1333425	3137	696	12939835	0.4849	0.1076	183	83%	2300	20148000	4885	
IL	Joppa	887	5	2014	1191697	2866	602	11893458	0.4819	0.1012	183	74%	2300	20148000	4854	
IL	Joppa	887	6	2014	1317637	3154	662	13094796	0.4818	0.1011	183	82%	2300	20148000	4853	
IL	Newton	6017	1	2014	3490220	8126	1440	32214778	0.5045	0.0894	617	65%	7449	65253240	16460	
					40806387	44382	18085	394920453	0.2248	0.0916	6496	72%				

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2014 SO2 Emissions	9439		169471959	0.111	Table 3
Dynegy Group 2014 SO2 Emissions Minus Baldwin 1, 3	6519		92926529	0.140	Table 4
Dynegy Group 2014 NOx Emissions		7251	169471959	0.086	Table 5
Dynegy Group 2014 NOx Emissions Minus Baldwin 1, 3		4022	92926529	0.087	Table 6
Old Ameren Group 2014 SO2 Emissions	34944		225448494	0.310	Table 7
Old Ameren Group 2014 NOx Emissions		10834	225448494	0.096	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		13896			Table 9
Dynegy Group NOx Emissions at Max Heat Input		10403			Table 11
Old Ameren NOx Emissions Max Heat Input		18109			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		41463	318375023	0.2605	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		14857	318375023	0.0933	Table 16

Attach 4
4/3/2018 testimon

r	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
14	3635208	10	1223	35557130	0.0006	0.0688	617	67%	5544	48565440	13	0.0006
14	2151742	22	656	20571870	0.0022	0.0638	389	63%	3282	28750320	31	0.0012
14	2477495	240	1065	22385698	0.0214	0.0952	441	64%	5025	44019000	472	0.0085
14	2111602	4244	704	20704034	0.4100	0.0680	364	66%	4594	40243440	8249	0.1085
14	1854000	4021	1723	18609882	0.4321	0.1851	281	75%	3321	29091960	6286	0.1579
14	1191697	2866	602	11893458	0.4819	0.1012	183	74%	2300	20148000	4854	0.1888
14	1333425	3137	696	12939835	0.4849	0.1076	183	83%	2300	20148000	4885	0.2147
14	1247131	2950	654	12153206	0.4855	0.1077	183	78%	2300	20148000	4891	0.2364
											29682	

nput (tons) **43579**

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 tons	Ma Gr SO
IL	Baldwin	889	1	2015	3929009	1503	1384	37866256	0.0794	0.0731	625	72%	6439	56405640	2238	
IL	Baldwin	889	2	2015	3016142	1062	985	28230422	0.0753	0.0698	635	54%	5985	52428600	1973	
IL	Baldwin	889	3	2015	4220738	1595	1879	42135390	0.0757	0.0892	635	76%	6400	56064000	2122	
IL	Havana	891	9	2015	2115992	858	892	23344525	0.0735	0.0764	488	49%	5518	48337680	1777	
IL	Hennepin	892	1	2015	439325	1048	317	4601595	0.4554	0.1379	75	67%	802	7025520	1600	
IL	Hennepin	892	2	2015	1246904	2922	893	12788515	0.4569	0.1396	231	62%	2518	22057680	5039	
IL	Coffeen	861	1	2015	1663873	21	567	15993139	0.0027	0.0709	389	49%	3282	28750320	38	
IL	Coffeen	861	2	2015	3324374	16	1048	33529517	0.0010	0.0625	617	62%	5544	48565440	23	
IL	Duck Creek	6016	1	2015	2363610	78	1012	22722935	0.0069	0.0891	441	61%	5025	44019000	152	
IL	ED Edwards	856	2	2015	1698538	3609	1683	16917465	0.4266	0.1989	281	69%	3321	29091960	6205	
IL	ED Edwards	856	3	2015	1475139	2826	458	13527349	0.4179	0.0677	364	46%	4594	40243440	8408	
IL	Joppa	887	1	2015	956900	2360	548	9580656	0.4927	0.1144	183	60%	2300	20148000	4963	
IL	Joppa	887	2	2015	871481	2131	502	8655055	0.4924	0.1161	183	54%	2300	20148000	4960	
IL	Joppa	887	3	2015	840144	2070	458	8363510	0.4949	0.1095	183	52%	2300	20148000	4986	
IL	Joppa	887	4	2015	921854	2268	501	9138359	0.4964	0.1096	183	58%	2300	20148000	5000	
IL	Joppa	887	5	2015	930759	2332	515	9581988	0.4866	0.1076	183	58%	2300	20148000	4902	
IL	Joppa	887	6	2015	810991	2070	441	8445632	0.4901	0.1044	183	51%	2300	20148000	4938	
IL	Newton	6017	1	2015	2842906	6938	1226	27378355	0.5068	0.0895	617	53%	7449	65253240	16537	
					33668679	35707	15309	332800663	0.2146	0.0920	6496	59%				

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2015 SO2 Emissions	8988		148966703	0.121	Table 3
Dynegy Group 2015 SO2 Emissions Minus Baldwin 1, 3	5890		68965057	0.171	Table 4
Dynegy Group 2015 NOx Emissions		6350	148966703	0.085	Table 5
Dynegy Group 2015 NOx Emissions Minus Baldwin 1, 3		3087	68965057	0.090	Table 6
Old Ameren Group 2015 SO2 Emissions	26719		183833960	0.291	Table 7
Old Ameren Group 2015 NOx Emissions		8959	183833960	0.097	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		14750			Table 9
Dynegy Group NOx Emissions at Max Heat Input		10262			Table 11
Old Ameren NOx Emissions Max Heat Input		18340			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		32609	252799017	0.2580	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		12046	252799017	0.0953	Table 16

Attach 5
4/3/18 Testin

r	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
15	3324374	16	1048	33529517	0.0010	0.0625	617	62%	5544	48565440	23	0.0010
15	1663873	21	567	15993139	0.0027	0.0709	389	49%	3282	28750320	38	0.0016
15	2363610	78	1012	22722935	0.0069	0.0891	441	61%	5025	44019000	152	0.0035
15	1475139	2826	458	13527349	0.4179	0.0677	364	46%	4594	40243440	8408	0.1067
15	1698538	3609	1683	16917465	0.4266	0.1989	281	69%	3321	29091960	6205	0.1555
15	930759	2332	515	9581988	0.4866	0.1076	183	58%	2300	20148000	4902	0.1872
15	810991	2070	441	8445632	0.4901	0.1044	183	51%	2300	20148000	4938	0.2136
15	871481	2131	502	8655055	0.4924	0.1161	183	54%	2300	20148000	4960	0.2360
											29628	

nput (tons) **44378**

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/ hour)	Max Heat Input	Max SO2 Tons	Ma Gr SO
IL	Baldwin	889	1	2017	4256973	1505	1593	38824663	0.0775	0.0821	625	78%	6439	56405640	2186	
IL	Baldwin	889	2	2017	4248869	1618	1638	40385824	0.0801	0.0811	635	76%	5985	52428600	2100	
IL	Baldwin	889	3	2017	0	0	0	0	0.0000	0.0000	635	0%	6400	56064000	2137	
IL	Havana	891	9	2017	2848787	1090	1240	30567133	0.0713	0.0811	488	67%	5518	48337680	1723	
IL	Hennepin	892	1	2017	438327	1124	328	4508524	0.4984	0.1453	75	67%	802	7025520	1751	
IL	Hennepin	892	2	2017	1378893	3495	1030	14201402	0.4922	0.1451	231	68%	2518	22057680	5428	
IL	Coffeen	861	1	2017	2149649	19	699	19939412	0.0019	0.0701	389	63%	3282	28750320	27	
IL	Coffeen	861	2	2017	3960975	29	1783	39101271	0.0015	0.0912	617	73%	5544	48565440	36	
IL	Duck Creek	6016	1	2017	2166840	25	1478	19985699	0.0025	0.1479	441	56%	5025	44019000	55	
IL	ED Edwards	856	2	2017	1262936	2726	1318	13212705	0.4126	0.1996	281	51%	3321	29091960	6002	
IL	ED Edwards	856	3	2017	2046863	3666	787	17698112	0.4142	0.0890	364	64%	4594	40243440	8335	
IL	Joppa	887	1	2017	875026	2158	522	8983253	0.4804	0.1161	183	55%	2300	20148000	4839	
IL	Joppa	887	2	2017	801348	1956	487	8140886	0.4804	0.1197	183	50%	2300	20148000	4840	
IL	Joppa	887	3	2017	685802	1702	400	7034467	0.4839	0.1137	183	43%	2300	20148000	4875	
IL	Joppa	887	4	2017	530810	1266	304	5244525	0.4826	0.1160	183	33%	2300	20148000	4862	
IL	Joppa	887	5	2017	627033	1547	353	6357587	0.4868	0.1110	183	39%	2300	20148000	4904	
IL	Joppa	887	6	2017	729089	1782	402	7292449	0.4888	0.1101	183	45%	2300	20148000	4924	
IL	Newton	6017	1	2017	3546555	4873	1538	33298298	0.2927	0.0924	617	66%	7449	65253240	9550	
					32554775	30578	15900	314776210	0.1943	0.1010	6496	57%				

	Tons	Tons	Heat Input	Rate	
Dynegy Group 2017 SO2 Emissions	8830		128487546	0.137	Table 3
Dynegy Group 2017 SO2 Emissions Minus Baldwin 1, 3	7326		89662883	0.163	Table 4
Dynegy Group 2017 NOx Emissions		5829	128487546	0.091	Table 5
Dynegy Group 2017 NOx Emissions Minus Baldwin 1, 3		4236	89662883	0.094	Table 6
Old Ameren Group 2017 SO2 Emissions	21748		186288664	0.233	Table 7
Old Ameren Group 2017 NOx Emissions		10071	186288664	0.108	Table 8
Dynegy Group SO2 Emissions at Max Heat Input		15325			Table 9
Dynegy Group NOx Emissions at Max Heat Input		11069			Table 11
Old Ameren NOx Emissions Max Heat Input		21103			Table 12
Combined MPS SO2 Minus Baldwin 1 and 3		29074	275951547	0.2107	Table 14
Combined MPS NOx Minus Baldwin 1 and 3		14307	275951547	0.1037	Table 16

Attach 4
4/3/2018 Tesla

r	Gross Load (MW-h)	SO2 (tons)	NOx (tons)	Heat Input (MMBtu)	SO2 Rate	NOx Rate	Nameplate Capacity (MW)	Capacity Factor	Nominal Capacity (mmBtu/hour)	Max Heat Input	Max SO2 tons	Max Group SO2 Rate
17	3960975	29	1783	39101271	0.0015	0.0912	617	73%	5544	48565440	36	0.0015
17	2149649	19	699	19939412	0.0019	0.0701	389	63%	3282	28750320	27	0.0016
17	2166840	25	1478	19985699	0.0025	0.1479	441	56%	5025	44019000	55	0.0019
17	3546555	4873	1538	33298298	0.2927	0.0924	617	66%	7449	65253240	9550	0.1036
17	1262936	2726	1318	13212705	0.4126	0.1996	281	51%	3321	29091960	6002	0.1453
17	2046863	3666	787	17698112	0.4142	0.0890	364	64%	4594	40243440	8335	0.1876
17	875026	2158	522	8983253	0.4804	0.1161	183	55%	2300	20148000	4839	0.2090
17	801348	1956	487	8140886	0.4804	0.1197	183	50%	2300	20148000	4840	0.2272
17	530810	1266	304	5244525	0.4826	0.1160	183	33%	2300	8592985	2073	0.2344
											35758	

nput

51083

Atta
4/3

State	Facility Name	Facility ID (ORISPL)	Unit ID	SO2 (tons)	NOx (tons)	2002 Heat Input (mmBtu)	2017 SO2 Rate (lb/mmBtu)	2017 NOx Rate (lb/mmBtu)	
IL	Baldwin	889	1	1701	1801	43884000	0.0775	0.0821	
IL	Baldwin	889	2	1487	1506	37135000	0.0801	0.0811	
IL	Baldwin	889	3	1768	2116	46403000	0.0762	0.0912	**NOTE: 2016 SO2 Rate and NOx Rate**
IL	Havana	891	9	1017	1156	28514000	0.0713	0.0811	
IL	Hennepin	892	1	1167	340	4684000	0.4984	0.1453	
IL	Hennepin	892	2	4325	1275	17575000	0.4922	0.1451	
IL	Coffeen	861	1	18	651	18570000	0.0019	0.0701	
IL	Coffeen	861	2	28	1712	37545000	0.0015	0.0912	
IL	Duck Creek	6016	1	28	1674	22635000	0.0025	0.1479	
IL	ED Edwards	856	2	3553	1719	17222000	0.4126	0.1996	
IL	ED Edwards	856	3	3308	711	15972000	0.4142	0.0890	
IL	Joppa	887	1	3254	786	13548000	0.4804	0.1161	
IL	Joppa	887	2	3905	973	16258000	0.4804	0.1197	
IL	Joppa	887	3	3725	875	15396000	0.4839	0.1137	
IL	Joppa	887	4	3234	777	13402000	0.4826	0.1160	
IL	Joppa	887	5	3674	838	15094000	0.4868	0.1110	
IL	Joppa	887	6	3926	884	16063000	0.4888	0.1101	
IL	Newton	6017	1	5946	1877	40631000	0.2927	0.0924	
				46064	21672	420531000	0.2191	0.1031	

	Tons	Tons	Heat Input	Rate	
Dynegy Group SO2 Emissions	11465		178195000	0.129	Table 3
Dynegy Group NOx Emissions		8195	178195000	0.092	Table 5
Old Ameren Group SO2 Emissions	34599		242336000	0.286	Table 7
Old Ameren Group NOx Emissions		13478	242336000	0.111	Table 8
COMBINED	**46064**	**21672**	**420531000**		

Table 10:

State	Facility Name	Facility ID (ORISPL)	Unit ID	SO2 (tons)	Heat Input (MMBtu)	Unit SO2 Rate	Group SO2 Rate	Unit NO2 Rate	NOx (tons)
IL	Coffeen	861	2	28	37545000	0.0015	0.0015	0.0912	1712
IL	Coffeen	861	1	18	18570000	0.0019	0.0016	0.0701	651
IL	Duck Creek	6016	1	28	22635000	0.0025	0.0019	0.1479	1674
IL	Newton	6017	1	5946	40631000	0.2927	0.1009	0.0924	1877
IL	ED Edwards	856	2	3553	17222000	0.4126	0.1402	0.1996	1719

308	15972000	0.4142	0.1688	0.0890	711
254	13548000	0.4804	0.1943	0.1161	786
905	16258000	0.4804	0.2198	0.1197	973
589	10728292	0.4826	0.2344	0.1160	622
629	**193109292**				**10725**
465	**178195000**				**8195**
094	**371304292**				**18920**

Tipsord, Marie

From: Armstrong, Andrew <AArmstrong@atg.state.il.us>
Sent: Tuesday, April 3, 2018 3:58 PM
To: Cacaccio, Maria; Powell, Mark; Tipsord, Marie; Lohrenz, Eric; aantoniolli@schiffhardin.com; jmore@schiffhardin.com; 'rgranholm@schiffhardin.com'; 'cajax@schiffhardin.com'; 'jvickers@elp.org'; 'jkreitner@elp.org'; khodge@hddattorneys.com; greg.wannier@sierraclub.org; 'fbugel@gmail.com'; Roccaforte, Gina; Vetterhoffer, Dana; Palumbo, Antonette; Khayyat, Katy
Cc: Sylvester, Stephen
Subject: [External] RE: In the Matter of Amendments to 35 Ill. Admin. Code 225.233 Multi-Pollutant Standards (R2018-020)

Two notes, to spare any confusion: (1) my references to "Attachment 9" on pages 3, 17, and 18 of my testimony should be to the spreadsheet filed as "Attachment 10"; and (2) my reference to "Attachments 9 and 10" in footnote 3 on page 4 should be to "Attachments 8 and 9".

Thank you.

Andrew Armstrong
Chief, Environmental Bureau/Springfield
Assistant Attorney General
Illinois Attorney General's Office
500 South Second Street
Springfield, IL 62706
(217) 782-7968

From: Cacaccio, Maria
Sent: Tuesday, April 03, 2018 3:51 PM
To: 'Mark.Powell@illinois.gov'; Marie.Tipsord@Illinois.Gov; Eric.Lohrenz@illinois.gov; aantoniolli@schiffhardin.com; jmore@schiffhardin.com; 'rgranholm@schiffhardin.com'; 'cajax@schiffhardin.com'; 'jvickers@elp.org'; 'jkreitner@elp.org'; khodge@hddattorneys.com; greg.wannier@sierraclub.org; 'fbugel@gmail.com'; 'gina.roccaforte@illinois.gov'; 'dana.vetterhoffer@illinois.gov'; 'antonette.palumbo@illinois.gov'; Katy.Khayyat@illinois.gov
Cc: Armstrong, Andrew; Sylvester, Stephen
Subject: In the Matter of Amendments to 35 Ill. Admin. Code 225.233 Multi-Pollutant Standards (R2018-020)

Good Afternoon,

Attached please find the Pre-Filed Testimony of Andrew Armstrong on behalf of the Illinois Attorney General's Office filed today in the above referenced matter with the Clerk of the Illinois Pollution Control Board via the "COOL" System and hereby served upon you.

The excel spreadsheets attached to the Pre-Filed Testimony of Andrew Armstrong were provided to Clerk of the Illinois Pollution Control Board via Email as attachments in their original form and are publically available on the website.

Thanks,

Maria Cacaccio

Maria Cacaccio
Paralegal I
Environmental Bureau
Office of the Illinois Attorney General
69 W. Washington Street, 18th Floor
Chicago, IL 60602
(312) 814-0669
MCacaccio@atg.state.il.us

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R18-20
AMENDMENTS TO	)	(Rulemaking – Air)
35 ILL. ADM. CODE 225.233,	)	
MULTI-POLLUTANT STANDARDS (MPS)	)	

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S PREFILED QUESTIONS

NOW COMES the Illinois Environmental Protection Agency, by one of its attorneys, and submits the following questions based upon the testimony submitted by Andrew Armstrong, on behalf of the Illinois Attorney General's Office.

1. Have you ever performed a Clean Air Act Section 110(l) analysis to demonstrate noninterference when revising a State Implementation Plan?

2. Have you communicated, either verbally or in writing, with any staff at USEPA Region 5 about this rulemaking?

   a. If so, who did you speak with and when?

   b. Please provide any written communications, if applicable, between you and USEPA Region 5.

3. Have you communicated, either verbally or in writing, with any staff at USEPA Region 5 about what is required to demonstrate noninterference under a Section 110(l) analysis?

   a. If so, who did you speak with and when?

   b. Please provide any written communications, if applicable, between you and USEPA Region 5.

Exhibit 38
R 18-20
4/17/2018
MT

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	
AMENDMENTS TO	)	**R18-20**
35 ILL. ADM. CODE 225.233,	)	**(Rulemaking – Air)**
MULTI-POLLUTANT STANDARDS (MPS)	)	

NOTICE OF FILING

To: ALL PARTIES ON THE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today electronically filed with the Office of the Clerk of the Illinois Pollution Control Board the attached **PREFILED QUESTIONS FOR ANDREW ARMSTRONG**, copies of which are herewith served upon you.

/s/ Ryan Granholm
Ryan Granholm

Dated: April 10, 2018

Ryan Granholm
SCHIFF HARDIN LLP
233 South Wacker Drive
Suite 7100
Chicago, Illinois 60606
312-258-5500

Exhibit 39
R18-20
4/17/2018
MT

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	
AMENDMENTS TO	)	**R18-20**
35 ILL. ADM. CODE 225.233,	)	**(Rulemaking – Air)**
MULTI-POLLUTANT STANDARDS (MPS)	)	

PREFILED QUESTIONS FOR ANDREW ARMSTRONG

NOW COME Dynegy Midwest Generation, LLC, Illinois Power Generating Company, Illinois Power Resources Generating, LLC and Electric Energy, Inc. (collectively, "the Companies"), by their attorneys, Schiff Hardin LLP, and hereby submit prefiled questions for Andrew Armstrong. The Companies request that the Hearing Officer allow follow-up questioning to be asked at hearing based on the answers provided.

1. Has the Illinois Attorney General's Office ("AGO") ever participated in a Clean Air Act Section 110(l) determination?
2. Has the AGO ever discussed a Clean Air Act Section 110(l) determination with the United States Environmental Protection Agency ("USEPA")?
3. According to footnote 16 of the AGO's December 11, 2017 pre-filed testimony (Board's Exhibit 9), an annual NO_X cap of 25,000 tons corresponds to a hypothetical year in which all MPS units ran at a 76.1% capacity factor, correct?
4. An SO_2 emissions cap of 49,000 tons, annually, is 73.8% of Illinois EPA's calculated "allowable emissions" of 66,354 tons, correct?
    a. So utilizing the methodology set forth on pages 15 and 16 (including footnote 16) of Exhibit 9, an annual SO_2 cap of 49,000 tons corresponds to a hypothetical year in which all MPS units ran at a 73.8% capacity factor, correct?
5. An SO_2 emissions cap of 34,094 tons, annually, is 51.3% of Illinois EPA's calculated "allowable emissions" of 66,354 tons, correct?
    a. So utilizing the methodology set forth on pages 15 and 16 (including footnote 16) of Exhibit 9, an annual SO_2 cap of 34,094 tons corresponds to a hypothetical year in which all MPS units ran at a 51.3% capacity factor, correct?
6. An NO_X emissions cap of 18,920 tons, annually, is 57.6% of Illinois EPA's calculated "allowable emissions" of 32,841 tons, correct?

a. So utilizing the methodology set forth on pages 15 and 16 (including footnote 16) of Exhibit 9, an annual NO_x cap of 18,920 tons corresponds to a hypothetical year in which all MPS units ran at a 57.6% capacity factor, correct?

7. On page 17 of Exhibit 9 the AGO states: "Thus, a more realistic framework for analysis than Illinois EPA's 'allowable emissions' is to identify the *actual* potential to emit which takes into account the real rate of pollution for each unit." (emphasis in original).

    a. Please turn to Attachment 6 of your April 3, 2018 pre-filed testimony. Does cell P50 contain the SO_2 "actual potential to emit," as that phrase appears in the quote above, for the MPS fleet using unit level emission rates for SO_2 from 2017? If not, please explain why not.

    b. The SO_2 "actual potential to emit" for the MPS fleet using unit level emission rates for SO_2 from 2017 is 51,083 tons, correct?

    c. Please turn to Attachment 6 of your April 3, 2018 pre-filed testimony. Does the addition of cells H30 and H31 represent the NO_x "actual potential to emit," as that phrase appears in the quote above, for the MPS fleet using unit level emission rates for NO_x from 2017? If not, please explain why not.

    d. The NO_x "actual potential to emit" for the MPS fleet using unit level emission rates for NO_x from 2017 is 32,172 tons, correct?

8. Was any of the operating and emission information presented in your April 3, 2018 pre-filed testimony, including the information contained in the attachments, available to you as of December 11, 2017? If not, please explain why that information was not available.

9. Was all of the operating and emission information presented in your April 3, 2018 pre-filed testimony, including the information contained in the attachments, available to you as of February 6, 2018? If not, please explain why that information was not available.

Respectfully submitted,

/s/ Ryan Granholm
Attorney for The Companies

Dated: April 10, 2018

SCHIFF HARDIN LLP
Josh More
Amy Antoniolli
Ryan Granholm
Caitlin Ajax
233 South Wacker Drive, Suite 7100
Chicago, Illinois 60606
(312) 258-5500

CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 10th day of April, 2018, I have electronically served the attached **PREFILED QUESTIONS FOR ANDREW ARMSTRONG**, upon all parties on the attached service list.

My e-mail address is rgranholm@schiffhardin.com;

The number of pages in the e-mail transmission is 6.

The e-mail transmission took place before 5:00 p.m.

/s/ Ryan Granholm
Ryan Granholm

Joshua More
Amy Antoniolli
Ryan Granholm
Caitlin Ajax
SCHIFF HARDIN LLP
233 South Wacker Drive
Suite 7100
Chicago, Illinois 60606
312-258-5500

SERVICE LIST	
Don Brown, Assistant Clerk Don.brown@illinois.gov Mark Powell, Hearing Officer Mark.Powell@illinois.gov Marie Tipsord, Hearing Officer Marie.Tipsord@illinois.gov Illinois Pollution Control Board James R. Thompson Center Suite 11-500 100 West Randolph Chicago, Illinois 60601	Antonette Palumbo Antonette.palumbo@illinois.gov Dana Vetterhoffer Dana.vetterhoffer@illinois.gov Gina Roccaforte Gina.roccaforte@illinois.gov Division of Legal Counsel Illinois Environmental Protection Agency 1021 North Grand Avenue, East P.O. Box 19276 Springfield, Illinois 62794-9276
Eric Lohrenz Eric.lohrenz@illinois.gov Office of General Counsel Illinois Department of Natural Resources One Natural Resources Way Springfield IL 62702-1271	Katy Khayat Katy.Khayyat@illinois.gov Department of Commerce and Economic Opportunity Small Business Office 500 East Monroe Street Springfield, IL 62701
Stephen Sylvester ssylvester@atg.state.il.us 69 West Washington Street, Suite 1800 Chicago, IL 60602 Andrew Armstrong aarmstrong@atg.state.il.us 500 South Second Street Springfield, IL 62706	Greg Wannier, Staff Attorney Greg.wannier@sierraclub.org Sierra Club Environmental Law Program 2101 Webster Street, Suite 3100 Oakland, CA 94612
Jean-Luc Kreitner jkreitner@elpc.org Justin Vickers jvickers@elpc.org 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	Katherine D. Hodge HeplerBroom LLC khodge@heplerbroom.com 4340 Acer Grove Drive Springfield, IL 62711
Faith Bugel fbugel@gmail.com 1004 Mohawk Wilmette, IL 60091	

ATTACHMENT A
R18-20
AMENDMENTS TO 35 ILL. ADM. CODE 225.233, MULTI-POLLUTANT STANDARDS

Questions for AGO Witness Andrew Armstrong

1. On page 2 of your testimony, you identify four MPS plants that are "relatively well-controlled for $S0_2$". Does anything in the current MPS standards prevent Dynegy or Vistra from shuttering any or all of these plants?

2. Beginning on page 5, you assert that the Board should evaluate the proposed MPS amendments using actual rather than maximum allowable emissions.

    a. If the Board adopts mass-based emissions caps at some level, should the Board be concerned about actual emissions as long as they remain less than or equal to the MPS caps? Why or why not?

    b. Has the Board ever adopted regulations predicated upon "actual" annual emissions? If not, why should the Board begin to do so now?

3. Aside from attachments to your testimony that outside parties prepared (*e.g.*, the Newton construction permit), who prepared each attachment? Did you review all of the attachments to your testimony in their entirety?

4. On page 19 of your testimony, you state that failing to reduce mass-based emission limitations when an MPS plant is retired or mothballed (while doing so when a plant is sold) would "encourage greater pollution and, moreover, incentivize retirement over sale." Please clarify how in your view this approach would encourage greater pollution, and from what baseline emissions could rise to greater levels. Also, explain why the incentive you have identified is inappropriate or otherwise to be avoided.

Exhibit 40
R18-20
4/17/2018
mst

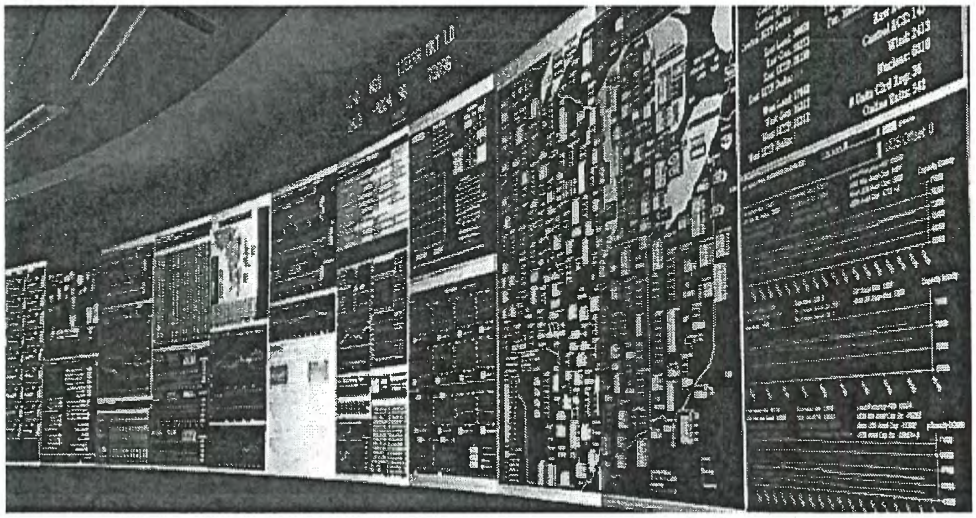
THE TRANSFORMATION OF THE ENERGY SECTOR

MARKETS

Weak MISO prices compound Ill. coal plant woes

Jeffrey Tomich and Edward Klump, E&E News reporters

Published: Friday, April 13, 2018



The Midcontinent Independent System Operator's control room in Carmel, Ind., in 2015. MISO

Three days after completing the roughly $2 billion purchase of rival Dynegy Inc., power producer Vistra Energy Corp. got another reminder of the struggles facing the Illinois coal plants it added to its fleet.

The region's grid operator, the Midcontinent Independent System Operator (MISO), announced clearing **prices** for its annual capacity auction yesterday afternoon. And the results will only fuel speculation that the company will close one or more of its Illinois plants.

Clearing prices for capacity across most of MISO's footprint for the year starting June 1 rose slightly to $10 per megawatt-day from $1.50, the grid operator said. The exception was in the windy northwest region of its footprint, where prices dipped to $1.

Overall, more than 135,000 megawatts was committed to meet forecast demand and planning reserve margins, MISO said.

While prices were a little higher, in part due to higher reserve margin requirements and a decrease in supply, they remain well below prices in neighboring grid PJM Interconnection (***Energywire***, May 24, 2017).

For Vistra's Illinois fleet, that only raises the stakes in the push for regulatory, market and policy reforms.

In an interview with E&E News before auction results were released, Vistra's CEO Curt Morgan wasn't optimistic about the likely MISO prices.

Vistra is in the midst of an operational review of power plants to identify potential efficiencies. But, Morgan noted, the Illinois fleet is "challenged."

Exh. 41
R18-20
4/17/18
MT

"We're likely going to have to retire some facilities there," he said, adding that such a decision could come as early as this year.

MISO's capacity market was long a source of discontent for predecessor Dynegy.

Prices are set through the annual Planning Resource Auction based on power plant supply and expected peak demand. The goal is to ensure there's ample generation available to call on during summer afternoons and other times when supplies might be tight.

Across most of MISO's sprawling footprint, the auction doesn't mean much. That's because utilities use their own power plant fleets to self-supply energy and ensure adequate capacity. Utilities can also lock up capacity by entering into negotiated contracts. Electricity retailers that don't self-supply or contract for capacity can purchase it through the auction.

In Illinois, the only fully deregulated state in MISO, the stakes are higher. There are no guarantees because prices there are set by the market, not regulators.

Dynegy complained for years that the MISO market design was unfair because power plant owners in neighboring states with excess generation to sell could bid it in at no cost, undercutting independent power producers that depend on capacity revenue.

That means there isn't adequate incentive for generators to make investments in existing power plants or to attract new ones, the company said.

Left unchanged, the company said, the result would ultimately be a generation shortage, higher prices and compromised reliability. A Dynegy executive in 2015 referred to the situation as a tsunami.

Pollution standards

While signs point to Illinois having ample generating capacity in the near term, MISO agrees that changes are needed to ensure that's the case over the longer term. The grid operator submitted a controversial proposal to the Federal Energy Regulatory Commission in late 2016 only to see FERC quickly reject it months later (***Energywire***, Feb. 6, 2017).

In May, MISO CEO John Bear asked the state of Illinois to address the issue in a letter to Republican Gov. Bruce Rauner. The governor, in turn, tasked utility regulators with overseeing a study and outlining potential policy solutions.

Dynegy proposed its own fix last year — legislation that would require the Illinois Power Agency to take over capacity procurement for consumers in southern Illinois that buy energy from alternative suppliers (***Energywire***, Dec. 6, 2017).

The company also convinced the Illinois EPA to propose a change in how the state's power plant emissions limits are administered. Dynegy said the proposal would provide more flexibility for how it operates its coal fleet without raising overall emissions.

Vistra's Morgan called the proposal to amend the state's Multi-Pollutant Standard the "highest priority" for the company in Illinois, noting that some of its plants with advanced pollution controls "are hugely out of the money" and are burning cash.

But environmental advocates and Illinois Attorney General Lisa Madigan (D) are challenging the rule change at the Illinois Pollution Control Board, arguing that it would let the company run its dirtier plants more frequently.

Consumer and environmental groups also challenge Dynegy's assertion that MISO's existing capacity market structure could result in price spikes or threaten grid reliability.

The groups also note that Illinois hasn't even begun to realize the benefits of the 2016 Future Energy Jobs Act, which will spur huge new investments in energy efficiency, wind and solar. The law will also ensure that Exelon Corp.'s Clinton nuclear station in MISO will remain in service for at least the next decade.

The most recent survey by MISO and the Organization of MISO States, a group of utility regulators from the grid operator's footprint, likewise suggests no shortfall in generating capacity. The survey, released annually in June, shows southern Illinois with a surplus of generation through at least mid-2022.

Ultimately, any change to the capacity market structure in Illinois will likely be up to the General Assembly. And legislators have shown little interest in advancing Dynegy's proposal only a year and a half after passing a sweeping energy law overhaul.

There, too, Vistra's CEO isn't optimistic.

"I don't see any support in Illinois to put in a separate capacity payment mechanism that people" will view "as a handout to coal plants," he said. "I hope I'm pleasantly surprised."

Twitter: **@jefftomich** | Email: **jtomich@eenews.net**

The essential news for energy & environment professionals

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	R2018–20
AMENDMENTS TO	)	(Rulemaking – Air)
35 ILL. ADM. CODE 225.233,	)	
MULTI-POLLUTANT STANDARDS (MPS)	)	

PRE-FILED TESTIMONY OF TAMARA DZUBAY
ON BEHALF OF ENVIRONMENTAL LAW & POLICY CENTER AND SIERRA CLUB

Environmental Law and Policy Center and Sierra Club hereby file the testimony of Tamara Dzubay directed to the Illinois Pollution Control Board in this matter, as provided by the Hearing Officer Order issued on March 14, 2018.

I. INTRODUCTION

My name is Tamara Dzubay and I am presenting testimony on behalf of the Environmental Law and Policy Center and the Sierra Club. I am a Clean Energy Finance Specialist at the Environmental Law & Policy Center in Chicago. I hold a Bachelor of Business Administration degree from the University of Michigan's Ross School of Business with a concentration in finance. I also hold a Master of Business Administration degree from Northwestern University's Kellogg School of Management where I majored in finance. I've worked in financial roles for seven years, three of those years in the energy industry. I have experience creating detailed cash flow financial models as well as energy pricing and operational models. I've guest lectured on *Topics in Energy & Sustainability*[1] at the University of Illinois at Chicago, presented on energy issues at state conferences and submitted comments on behalf of the Environmental Law & Policy Center to numerous state agencies and regulatory authorities in the Midwest region.

[1]Univ. of Ill. at Chi., *LAS 493: Topics in Energy & Sustainability* (Spring 2018), https://uicsustainablemobility.wordpress.com/spring-2018-guest-lectures/ (last visited Apr. 3,2018).

Exhibit 42
R18-20
4/17/2018
MW

II. QUESTIONS AND ANSWERS

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to show that as of year-end 2017, Dynegy's MISO segment is cash flow positive, not negative as has been suggested numerous times in this rulemaking. In doing so, I explain some of the financial terminology that has been used in this rulemaking. Explaining this terminology helps demonstrate why Dynegy has painted a misleading picture of the financial situation of the plants at issue.

Q. Do you have any overarching concerns with how Dynegy has presented its financial situation in this rulemaking?

A. Yes. Throughout this rulemaking, Dynegy has repeatedly and misleadingly conflated a number of financial metrics in a way that overstates their financial problems. Dynegy has presented the MISO segment as being cash flow negative by pointing to metrics that do not equate to cash flow when in fact the metric that best represents the cash flow position of the segment is positive. As of year-end 2017, the only financial metric that is presented in Dynegy's SEC filings as being negative for the MISO segment is the operating loss, which is driven by a non-cash impairment expense from the second quarter. Dynegy has written down the value of some of its plants through impairment charges, which leads to a lower cost basis and thus lower future depreciation expenses. These lower depreciation expenses are one of the reasons that the MISO segment had an operating income of $6 million in the fourth quarter of 2017 compared to an operating loss of $42 million in the fourth quarter of 2016. My testimony will further explain these issues.

Q. What is Dynegy's MISO segment?

A. As Dynegy confirmed in response to the Environmental Group's pre-filed questions from the last hearing, the MISO segment represents what was formerly both the MISO and IPH segments.

1. Turn to Attachment A below, which is Dynegy's 10-K SEC filing for 2017 ("2017 10-K"). On pages 2-3 of the 2017 10-K, can you confirm that Dynegy combined the MISO segment and IPH segment into a single MISO segment?[2]

A. So in answer to question number one, yes.[3]

The combined MISO segment includes the Baldwin, Havana, and Hennepin plants (the Dynegy MPS group excluding the Vermilion and Wood River plants which are no longer operating) and the Coffeen, Duck Creek, E.D. Edwards, Joppa, and Newton plants (the Ameren MPS group excluding the Hutsonville and Meredosia plants which are no longer operating).[4]

Q. In his pre-filed testimony, Dynegy's Dean Ellis made the following statement:

> **In other words, in order for Dynegy to operate it must bid into MISO higher-cost, lower emitting units along with the lower-cost, higher emitting units.** ***This situation results in Dynegy's fleet operating on a negative cash flow basis, that is, revenues received are less than the fuel and other operating costs incurred to operate the unit.***[5]

In your experience, is this a typical definition of "negative cash flow?"

---

[2] R18-20, Environmental Groups' Prefiled Questions for Dynegy's Witnesses (Mar. 2, 2018) at 1.
[3] Mar. 6, 2018 Tr. 74:1-18.
[4] *See* R18-20, IEPA Statement of Reasons (Oct. 2, 2017) at 2.
[5] R18-20, Dynegy Testimony of Dean Ellis (Dec. 11, 2017) at 11.

A. No. Mr. Ellis's definition is more in line with Dynegy's definition of gross margin (also commonly referred to as gross profit). For example, Dynegy's SEC filings define gross margin as operating revenues minus operating costs.[6]

Q. Is negative cash flow the same as negative gross margin?

A. No, it is not. A negative cash flow would mean that cash flowing out of the business unit exceeds cash coming into the business unit. A negative gross margin would indicate that the costs of goods/services sold exceed sales revenues, or in the case of Dynegy, that operating costs exceed operating revenues.

Gross margin does not equate to the cash position of a firm. For example, revenues are booked when a sales transaction takes place and don't necessarily represent cash on hand. This is the case when you purchase something with a credit card, and you are not immediately exchanging cash. The sale is booked as revenue on the merchant's income statement, but cash has not actually been exchanged so under the asset section of the merchant's balance sheet, accounts receivable would increase. Another example is that certain uses of cash, such as the purchase of equipment or expenditures on inventory purchased but not yet sold (such as a power plant's stockpile of coal[7]) are not reflected as cost of goods/services sold (or in the case of Dynegy, operating costs) on the income statement. They are reflected as property, plant and equipment and inventory on the balance sheet.

---

[6] *See* Exhibit A — Dynegy's Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 for the MISO segment.

[7] *See* U.S. Energy Info. Admin., *Days of burn by non-lignite coal rank, January 2009—January 2018* (Mar. 23, 2018), https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.php#tabs_stocks2-1.

Q. Was the MISO segment's gross margin for the last reporting period negative?

A. No, the MISO segment's gross margin for the last reporting period was positive. Specifically, for the last reporting period (calendar year 2017) the MISO segment had a gross margin of $429 million.[8]

Q. How would you determine whether the MISO segment is operating on a negative cash flow basis?

A. I would determine this by calculating the MISO segment's free cash flow.

Q. What is free cash flow?

A. Free cash flow is a financial metric that determines the amount of cash that is available after accounting for necessary expenses needed to run and grow a business.[9]

Q. Why is free cash flow important?

A. Free cash flow is important because for a company to remain functional, it must have sufficient cash to meet short-term obligations needed to continue operating the business. Short-term obligations are often referred to as working capital requirements. Additionally, for a company to grow, it must invest in capital expenditures. Free cash flow takes into account the expenses that are necessary to meet short-term obligations as well as the expenses that are necessary to invest in capital expenditures.

Q. How is free cash flow calculated?

---

[8] *See* Exhibit A— Dynegy's Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 for the MISO segment.

[9] *See* JONATHAN BERK &PETER DEMARZO, CORPORATE FINANCE 241-254 (Donna Battista et al. eds., 3d ed. 2014).

A. Free cash flow is typically calculated as net operating profit after tax plus non-cash expenses minus capital expenditures minus change in net working capital.[10]

Q. What is net working capital?

A. It represents the capital that is needed or available to run the business over the short-term.[11] The text book *Corporate Finance* provides a succinct explanation:

> Firms may need to maintain inventories of raw materials and finished product to accommodate production uncertainties and demand fluctuations. Also, customers may not pay for the goods they purchase immediately. While sales are immediately counted as part of earnings, the firm does not receive any cash until the customers actually pay. In the interim, the firm includes the amount that customers owe in its receivables. Thus, the firm's receivables measure the total credit that the firm has extended to its customers. In the same way, payables measure the credit the firm has received from its suppliers...Any increases in net working capital represent an investment that reduces the cash that is available to the firm and so reduces free cash flow.[12]

Q. Based on this formula and using the best available public information from Dynegy's SEC filings, would you conclude that the MISO segment's free cash flow for the last reporting period was negative?

---

[10] *See id.* at 243, 248.
[11] *See id.* at 242, 1057.
[12] *Id.* at 242.

A. No. I would conclude that the MISO segment's free cash flow for the last reporting period was positive. Specifically, the MISO segment had a free cash flow of **$116.9 million** for the last reporting period. I have included this calculation in *Exhibit B - Textbook Calculation of MISO Segment's Free Cash Flow.*[13]

Q. Mr. Ellis testified at the March 6 hearing regarding how to calculate free cash flow:

> **A. With regard to any information that documents the negative cash flow for the MISO segment, one could refer to a combination of the operating income and the [capital expenditures] to determine the cash flow position of the segment.**
>
> **Q. So typically, do you include non-cash expenditures when calculating cash flow?**
>
> **A. We would typically take out non-cash items.**[14]

If you use these inputs to calculate free cash flow for the MISO segment, what is the result?

A. This would result in a free cash flow figure of **$117 million** for the MISO segment for the last reporting period.[15]

Q. Is there any other indication of how Dynegy calculates free cash flow in its SEC filings?

A. Yes, in the Dynegy/Vistra merger filing, Dynegy Management prepared financial forecasts of the company's gross margin, adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA) and free cash flow through 2021.[16] While these projections are for the company as a whole, they show that the free cash flow for the MISO segment can be calculated as adjusted EBITDA minus capital expenditures. Using this calculation, the MISO segment's

---

[13] *See* Exhibit B—Textbook Calculation of MISO Segment's Free Cash Flow.
[14] Mar. 6, 2018 Tr. 77:20-78:23.
[15] *See* Exhibit C—Dean Ellis' Calculation of Free Cash Flow.
[16] *See* Exhibit D—Dynegy Management Projections.

free cash flow for the last reporting period (calendar year 2017) is **$123 million.**[17] The result is $6 million higher than the calculation derived from Mr. Ellis's calculation because it includes certain one-time charges and other items that are documented in *Exhibit F – Difference in Dynegy's Calculations*.[18]

Q. Why do you think Dynegy Management focuses on Gross Margin, Adjusted EBITDA and Free Cash Flow in its financial projections?

A. I assume the company finds these metrics to be important determinants of financial health. Gross margin indicates whether revenues exceed costs of services.[19] Adjusted EBITDA is meant to reflect operating performance.[20] As I mentioned previously, free cash flow determines the amount of cash that is available after accounting for necessary expenses needed to run and grow a business. According to Dynegy's SEC filings, for the last reporting period, the MISO segment had a gross margin of $429 million, an adjusted EBITDA of $152 million and free cash flow of $123 million.[21]

Q. In Dynegy's Responses to Questions for Dynegy's Witnesses, Dynegy states that the Illinois fleet is cash flow negative and backs this statement up by pointing to the operating loss for the MPS fleet:

> **As a whole, the Illinois fleet is cashflow negative. Specifically, for the nine months ending September 30, 2017, the "MISO" segment reported an**

[17] *See* Exhibit E— Free Cash Flow Calculation for the MISO Segment Based on Formula Presented in Dynegy Management Projections.
[18] *See* Exhibit F— Difference in Dynegy's Calculations.
[19] *See* Exhibit D— Dynegy Management Projections.
[20] *See* Dynegy Inc., Annual Report (Form 10-K) 45 (Feb. 22, 2018).
[21] *See* Exhibit A— Dynegy's Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 for the MISO segment; Exhibit D— Dynegy Management Projections; Exhibit E— Free Cash Flow Calculation for the MISO Segment Based on Formula Presented in Dynegy Management Projections.

> **operating loss of $90 million and the "IPH" segment reported an operating income of $40 million, for a total net operating loss of $50 million for the MPS fleet.**[22]

Does the operating loss indicate that the Illinois fleet is cashflow negative?

A. No, it does not. Dynegy's operating loss does not equate to the Illinois fleet being cash flow negative.

Q. Can you please explain the differences?

A. To do this, it is necessary to explain the difference between earnings and cash flow. Operating income or loss is a measure of a firm's earnings. Cash flow, on the other hand, is the net amount of cash moving into and out of a business and indicative of liquidity. The text book *Corporate Finance* provides a succinct explanation of the difference:

> Earnings are an accounting measure of the firm's performance. They do not represent real profits: The firm cannot use its earnings to buy goods, pay employees, or fund new investments. To do those things, a firm needs cash. Thus, to evaluate a capital budgeting decision, we must determine its consequences for the firm's available cash.
>
> There are important differences between earnings and cash flow. Earnings include non-cash charges, but do not include the cost of capital investment. To determine free cash flow from incremental earnings, we must adjust for these differences.[23]

Q. Do you agree that the MISO segment is cash flow negative?

A. No. As I mentioned previously, I would calculate the MISO segment's free cash flow by using the best available public information from Dynegy's SEC filings, which I have done in *Exhibit B - Textbook Calculation of MISO Segment's Free Cash Flow*.[24] The calculation results in $116.9 million in free cash flow for the MISO segment. Therefore, I would not agree that the

---

[22] R18-20, Dynegy's Responses to Questions (Feb. 16, 2018) at 3.
[23] BERK, *supra* note 9, at 241.
[24] *See* Exhibit B—Textbook Calculation of MISO Segment's Free Cash Flow.

MISO segment is cash flow negative. While the cash flow position of the segment is an important financial indicator, the MISO segment is not cash flow negative.

Q. Based on your testimony, it appears that in this rulemaking Mr. Ellis has conflated both gross margin with negative cash flow and operating loss with negative cash flow, is this correct?

A. Yes, and it is incorrect to conflate these metrics. The MISO segment's gross margin does not equate to cash flow and neither does the MISO segment's operating income/loss.

Q. How would you describe the last reporting period according to these metrics?

A. The MISO segment was cash flow positive but incurred an operating loss.

Q. What were the drivers of the MISO segment's operating loss.

A. Non-cash expenses were the drivers. Specifically, the non-cash expenses of depreciation and impairments drove the MISO segment's operating loss.

Q. What is a non-cash depreciation expense?

A. Fixed assets, such as the MISO segment plants, incur a non-cash depreciation expense for accounting purposes according to a depreciation schedule that is dependent on the asset's useful life. This expense is meant to reflect the wear and tear on an asset over a given period and appears on the income statement to write down the value of the asset on the balance sheet.

Q. What is a non-cash impairment expense?

A. Long-lived assets, such as Dynegy's plants, are listed on the balance sheet at their book value. When an asset is purchased, the book value is the acquisition cost less its accumulated depreciation expense.[25] When an asset is built, the book value is typically calculated through a net present value calculation of discounting future cash flows at a risk-adjusted rate of return. When circumstances indicate that the book value of an asset on the balance sheet is less than its fair market value and that the loss is unrecoverable, a company can book an impairment charge on the income statement to write down the value of the asset on the balance sheet. Dynegy's explanation of impairments is attached in *Exhibit G – Impairment of Long-Lived Assets*.[26]

Q. How does an impairment expense relate to an asset's current market value?

A. An impairment expense is meant to reduce the value of an asset to reflect its current market value.

Q. Are there any other circumstances when assets are adjusted to their current market value?

A. Yes, in mergers and acquisitions the acquiring company typically values the acquiree's assets at their fair market value.

Q. In the Vistra/Dynegy merger, is Vistra (the acquiring company) valuing Dynegy's assets at their fair market value?

A. Yes. Below is an excerpt from the Vistra/Dynegy merger filing that can be found under the heading Anticipated Accounting Treatment.

[25] *See id.* at 1048.
[26] *See* Exhibit G— Impairment of Long-Lived Assets.

> Dynegy's assets acquired, liabilities assumed and non-controlling interests will be measured at their respective fair values as of the closing date of the Merger.[27]

In other words, after the merger all of Dynegy's plants are going to be marked at their current value, not just the plants that incurred impairment expenses.

Q. Would this have any effect on the future profitability of these plants?

A. Yes. In US accounting practices, the Accounting Standards Codification is the current single source of United States Generally Accepted Accounting Principles (GAAP). As explained in the Accounting Standards Codification:

> **Property, Plant, and Equipment — Overall**
> **Subsequent Measurement**
> **360-10-35-20-** If an impairment loss is recognized, the adjusted carrying amount of a long-lived asset shall be its new cost basis. For a depreciable long-lived asset, the new cost basis shall be depreciated over the remaining useful life of that asset.

Once an impairment loss is allocated to the carrying values of the long-lived asset held and used, the reduced carrying amount represents the new cost basis of the long-lived asset. As a result, entities are prohibited from reversing the impairment loss should facts and circumstances change. In addition, future depreciation or amortization would be based on the asset's new cost basis.[28]

Ernst & Young's report on *Impairment or disposal of long-lived assets* notes the consequence of Accounting Standards Codification **360-10-35-20** below.

> An interesting consequence of the [Financial Accounting Standards Board's] approach is that if fair value is determined by discounting future cash flows at a risk-adjusted rate of return, the written-down assets likely will be very profitable in the future if the entity

[27] Dynegy Inc., Proxy Statement (Schedule 14A) 135 (Jan. 25, 2018).
[28] Ernst &Young, *Financial reporting developments: A comprehensive guide – Impairment or disposal of long-lived assets* 42 (2017), http://www.ey.com/publication/vwluassetsdld/financialreportingdevelopments_bb1887_impairment_15december2017-v2/$file/financialreportingdevelopments_bb1887_impairment_15december2017-v2.pdf?OpenElement.
Ernst & Young is one of the "Big Four" reputable accounting firms that together handle the vast majority of audits for public and private companies.

achieves the cash flows used in the model. The new cost basis will result in significantly lower depreciation charges while the assets will generate cash flows providing a risk-adjusted rate of return.[29]

Q. Did Dynegy determine fair value by discounting future cash flows at a risk-adjusted rate of return when calculating impairment charges for the MISO plants, as is suggested in the italicized section below from Ernst & Young's report:

> ***[I]f fair value is determined by discounting future cash flows at a risk-adjusted rate of return*, the written-down assets likely will be very profitable in the future if the entity achieves the cash flows used in the model.**[30]

A. Yes. The 2017 impairment charges of $10 million to write down the value of the Hennepin plant and $89 million to write down the value of the Havana plant were measured using a discounted cash flow (DCF) model.[31] A discounted cash flow model discounts expected future cash flows at a risk-adjusted rate of return. The table also shows that in 2016 Dynegy booked a $645 million impairment charge to write down the value of Baldwin.

Q. Below is testimony by Mr. Ellis from the most recent hearing in this rulemaking:

> **Q Does Dynegy still plan to mothball Baldwin Unit Number 1 this year?**
>
> **A [By Dean Ellis} At this point, Dynegy has no plans to mothball that unit this year.**
>
> **Q Did they previously have plans to do mothball Baldwin Number 1 in '18?**
>
> **A It was under consideration, but at this point, we haven't given it any additional consideration.**
>
> **Q And I guess my follow-up question would be, what changed to change this Dynegy strategy regarding Baldwin 1?**
>
> **A We were able to defer some capital expenditures and operational expenditures which helped the near term financial operational outlook of the unit.**[32]

---

[29] *Id.*
[30] *Id.*
[31] *See* Exhibit H— Dynegy's Impairment Table.
[32] Mar. 12, 2018 Tr. 59:7-22.

What does that testimony tell you?

A. Mr. Ellis stated that Baldwin is no longer slated for mothball.

Q. Do you believe this consequence of written down assets being very profitable in the future could be related to Baldwin no longer being slated for mothball?

A. Yes. It is possible that the impairment charge at Baldwin led to significantly lower depreciation expenses at the unit which makes the plant more profitable. This could be why it is no longer slated for mothball.

Q. Why do you think the Duck Creek and Coffeen plants that have been presented as needing operational flexibility due to poor financial performance are not listed on Dynegy's table as being "impaired"?

A. It could be because Dynegy acquired these plants in 2013 along with the other plants that formerly comprised the IPH segment at no stock or cash consideration. In order to determine the purchase price for the purposes of valuing the assets on the balance sheet, Dynegy estimated the fair value of the plants using a discounted cash flow model. The MISO capacity auction price at that time was low so if Dynegy used the current market conditions to predict future cash flows, it is likely that the cash flows have been achievable which is why Duck Creek and Coffeen aren't listed as impaired.[33]

Q. If the cash flows for Duck Creek and Coffeen were achieved, does that indicate the plants are performing at least as well as Dynegy expected them to?

---

[33] *See Note 3—Merger and Acquisitions*, SEC.GOV, https://www.sec.gov/Archives/edgar/data/1379895/000137989514000004/R11.htm (last visited Apr. 3, 2018).

A. Yes, that would be the indication.

Q. Did Vistra determine fair value by discounting future cash flows at a risk-adjusted rate of return when measuring the value of Dynegy's assets in the merger?

A. Yes. As Dynegy and Vistra explained in their merger filing:

> The fair value of Dynegy's property, plant and equipment related to its power generation assets was estimated using a discounted cash flow method which was based on a number of factors including forecasted power prices, fuel prices, capacity revenues, operating parameters, operating and maintenance costs and other variables. The cash flows for each respective generation asset were discounted using rates between 7% and 9%, depending on the related technology and market that each respective asset operates in.[34]

Q. Knowing that Dynegy and Vistra determined fair value by discounting future cash flows at a risk-adjusted rate of return, do you think the cash flows used in the models are achievable, as is suggested in the italicized section below from Ernst & Young's report:

> **If fair value is determined by discounting future cash flows at a risk-adjusted rate of return, the written-down assets likely will be very profitable in the future *if the entity achieves the cash flows used in the model.***

A. Yes. These models forecasted cash flows at a time when the MISO capacity price is very low at $1.50 ($/MW-Day). To put this into context, the prior year the MISO capacity auction price was $72 ($/MW-Day). The year before that, the MISO capacity auction price was $150 ($/MW-Day). Therefore, I believe the cash flows used in the model would be achievable.[35]

---

[34]*See* Schedule 14A, *supra* note 27, at 322.
[35]*See Resource Adequacy*, MISOENERGY.ORG, https://www.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3APRA%20Document%2Fplanningyear%3APY%2016-17&t=10&p=0&s=FileName&sd=desc (last visited Apr. 2, 2018).

Q. Assuming the cash flows used in the models are achievable, if the MISO segment operates under the same circumstances next year as it did this year, would the segment have an operating profit?

A. Yes. Assuming the cash flows are achievable and that the MISO segment operates under roughly the same circumstances or better, the segment would not incur the non-cash impairment expenses which are driving the loss and the non-cash depreciation expense would also be lower. This would result in an operating profit of at least $55 million.

Q. So that would mean that all of the financial metrics used in this rulemaking for the MISO segment would be positive?

A. Yes. According to Dynegy's SEC filings, the MISO segment's 2017 year-end gross margin was $429 million; the MISO segment's year-end 2017 adjusted EBITDA was $152 million; the MISO segment's year-end 2017 free cash flow was $123 million. If the non-cash impairment expenses are not included, the MISO segment shows $55 million in operating profit instead of an operating loss of $44 million.[36]

III. CONCLUSION

This concludes my testimony.

[36] *See* Exhibit A— Dynegy's Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 for the MISO segment; Exhibit D— Dynegy Management Projections; Exhibit E— Free Cash Flow Calculation for the MISO Segment Based on Formula Presented in Dynegy Management Projections.

Respectfully submitted,

Date: April 3, 2018

/s/Tamara Dzubay
Tamara Dzubay
Environmental Law & Policy Center
35 E. Upper Wacker Dr., Ste. 1600
Chicago, IL 60601
T: (312) 795-3733
F: (312) 795-3730
tdzubay@elpc.org

<u>Exhibits to Prefiled Testimony of Tamara Dzubay</u>

Exhibit A— Dynegy's Discussion of Segment Adjusted EBITDA — Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 for the MISO segment

Exhibit B— Textbook Calculation of MISO Segment's Free Cash Flow

Exhibit C— Dean Ellis' Calculation of Free Cash Flow

Exhibit D— Dynegy Management Projections

Exhibit E— Free Cash Flow Calculation for the MISO Segment Based on Formula Presented in Dynegy Management Projections

Exhibit F— Difference in Dynegy's Calculations

Exhibit G— Impairment of Long-Lived Assets

Exhibit H— Dynegy's Impairment Table

Table of Contents

Exhibit A— Dynegy's Discussion of Segment Adjusted EBITDA — Year Ended December 31,
2017 Compared to Year Ended December 31, 2016 for the MISO segment

MISO Segment

The following table provides summary financial data regarding our MISO segment results of operations for the years ended December 31, 2017 and 2016, respectively:

(dollars in millions, except for price information)	Year Ended December 31, 2017	Year Ended December 31, 2016	Favorable (Unfavorable) $ Change
Operating Revenues			
Energy	$ 920	$ 1,027	$ (107)
Capacity	210	163	47
Mark-to-market income (loss), net	21	(47)	68
Contract amortization	(6)	(13)	7
Other	7	7	—
Total operating revenues	1,152	1,137	15
Operating Costs			
Cost of sales	(731)	(762)	31
Contract amortization	8	21	(13)
Total operating costs	(723)	(741)	18
Gross margin	429	396	33
Operating and maintenance expense	(300)	(347)	47
Depreciation expense	(75)	(81)	6
Impairments	(99)	(793)	694
Gain on sale of assets, net	1	1	—
Acquisition and integration costs	—	8	(8)
Other	—	(16)	16
Operating loss	(44)	(832)	788
Depreciation and amortization expense	91	87	4
Bankruptcy reorganization items	494	(96)	590
Other income and expense, net	26	15	11
EBITDA	567	(826)	1,393
Adjustments to reflect Adjusted EBITDA from noncontrolling interest	2	2	—
Acquisition, integration, restructuring and bankruptcy reorganization costs	—	(8)	8
Bankruptcy reorganization items	(494)	96	(590)
Mark-to-market adjustments	(21)	47	(68)
Impairments	99	793	(694)
Gain on sale of assets, net	(1)	(1)	—
Non-cash compensation expense	1	6	(5)
Other (1)	(1)	20	(21)
Adjusted EBITDA	$ 152	$ 129	$ 23
Million Megawatt Hours Generated	29.1	29.8	(0.7)
IMA for Coal-Fired Facilities (2)	89%	89%	
Average Capacity Factor for Coal-Fired Facilities (3)	63%	53%	
CDDs (4)	1,272	1,652	(380)
HDDs (4)	4,534	4,662	(128)
Average Market On-Peak Power Prices ($/MWh) (5):			
Indiana (Indy Hub)	$ 34.36	$ 33.71	$ 0.65
Commonwealth Edison (NI Hub)	$ 32.28	$ 31.98	$ 0.30

Exhibit B— Textbook Calculation of MISO Segment's Free Cash Flow

Source: Dynegy's 2017 10-K
Note: Calculations are based on year-end 2017 financial results

MISO Segment Free Cash Flow		
Net Operating Profit After Tax	-28.6	See calculation below
Plus Non-cash Expenses	190	See calculation below
Minus Capital Expenditures	29	p. 41 of the 2017 10-K
Minus Change in Net Working Capital	15.5	See calculation below
Free Cash Flow (in millions)	**$116.9**	
Net Operating Profit After Tax Calculation		
Operating Income/Loss	-44	p. 57 of the 2017 10-K
Times 1 - tax rate of 35%	65%	p. 10 of the 2017 10-K
Total	**-28.6**	
Non-cash Expenses Calculation		
Plus Depreciation & Amortization	91	p. 57 of the 2017 10-K
Plus Impairments	99	p. 57 of the 2017 10-K
Total	**190**	
Change in Net Working Capital Calculation For Company*		
Plus Change in Accounts Receivable	127	F-4 of the 2017 10-K
Plus Change in Inventory	0	F-4 of the 2017 10-K
Plus Change in Prepayments	-6	F-4 of the 2017 10-K
Minus Change in Accounts Payable	35	F-5 of the 2017 10-K
Minus Change in Accrued Liabilities and Other Current Liabilities	21	F-5 of the 2017 10-K
Total	**65**	
Change in Working Capital Calculation For MISO Segment		
Change in Working Capital for Company	**65**	See calculation above
Times MISO Contribution to Revenues	**23.8%**	See calculation below
Total	**15.5**	
MISO contribution to revenues		
MISO Revenues	1,152	F-61 of the 2017 10-K
Consolidated Company Revenues	4,842	F-61 of the 2017 10-K
Total	**23.8%**	

*Net working capital is calculated as current operating assets minus current operating liabilities.
Change in net working capital is calculated as net working capital in 2017 minus net working capital in 2016.

Exhibit C— Dean Ellis' Calculation of Free Cash Flow

Source: Dynegy's 2017 10-K
Note: Calculations are based on year-end 2017 financial results

MISO Segment Free Cash Flow		
Operating Income/Loss	-44	p. 57 of the 2017 10-K
Minus Capital Expenditures	29	p. 41 of the 2017 10-K
Plus Non-cash Expenses	190	See calculation below
Free Cash Flow (in millions)	**$117**	
Non-cash Items Calculation		
Plus Depreciation & Amortization	91	p. 57 of the 2017 10-K
Plus Impairments	99	p. 57 of the 2017 10-K
Total	**190**	

Exhibit D— Dynegy Management Projections

Table of Contents

Except to the extent required by applicable federal securities laws, Dynegy has not updated, and expressly disclaims any responsibility to update or otherwise revise, the Dynegy Management Projections to reflect circumstances existing after the date when Dynegy senior management prepared the Dynegy Management Projections or to reflect the occurrence of future events or changes in general economic or industry conditions, even in the event that any of the assumptions underlying the Dynegy Management Projections are shown to be in error. Dynegy urges all Dynegy stockholders to review Dynegy's most recent SEC filings for information relating to Dynegy's reported financial results.

Certain of the measures included in the Dynegy Management Projections may be considered non-GAAP financial measures, including EBITDA (Adjusted EBITDA) and Unlevered Free Cash Flow (Adjusted Free Cash Flow). Non-GAAP financial measures should not be considered in isolation from, or as a substitute for, or superior to, financial information presented in compliance with GAAP. Non-GAAP financial measures used by Dynegy may not be comparable to similarly titled amounts used by other companies. In addition, the quantitative reconciliation of the forward-looking non-GAAP financial measures omits a reconciliation of Net Income to EBITDA because Dynegy would not be able to provide such reconciliation without unreasonable efforts.

Dynegy Management Projections

Fiscal year ending December 31,

	($ in millions)				
	2017E(6)	2018E	2019E	2020E	2021E
Gross Margin(1)	—	**2,566**	**2,390**	**2,126**	**2,067**
Fixed O&M	—	(953)	(921)	(927)	(949)
SG&A	—	(140)	(141)	(144)	(147)
Other	—	(6)	10	32	49
EBITDA (Adjusted EBITDA)(2)	**1,160**	**1,468**	**1,338**	**1,087**	**1,021**
Capex(3)	—	(279)	(266)	(260)	(207)
AROs	—	(36)	(38)	(7)	(23)
Pension / LTSA / Other(4)	—	(28)	(38)	2	(86)
Unlevered Free Cash Flow (Adjusted Free Cash Flow)(5)	—	**1,125**	**996**	**822**	**704**

(1) Gross Margin means revenue minus costs of services.
(2) The non-GAAP measure EBITDA (Adjusted EBITDA) means Gross Margin, minus Fixed O&M, SG&A and Other.
(3) Includes maintenance, environmental and growth capital expenditures. Also includes environmental capex attributable to EPA's Effluent Limitations Guidelines, EPA's final rule regarding Section 316(a) and 316(b) in the Clean Water Act, and EPA's final rule regarding the safe disposal of coal combustion residuals.
(4) Includes LTSA adjustments and funding requirements for pensions and ARO outlays for operating assets and announced retirements.
(5) The non-GAAP measure Unlevered Free Cash Flow (Adjusted Free Cash Flow) means EBITDA (Adjusted EBITDA), minus Capex, AROs and Pension / LTSA / Other.
(6) Assumes pro forma for sale of Milford (MA), Dighton, Lee, Troy and Armstrong as if sales closed January 1, 2017.

Exhibit E— Free Cash Flow Calculation for the MISO Segment Based on Formula Presented in Dynegy Management Projections

Source: Dynegy's 2017 10-K

Note: Calculations are based on year-end 2017 financial results

MISO Segment Free Cash Flow		
Adjusted EBITDA	152	p. 57 of the 2017 10-K
Minus Capital Expenditures	29	p. 41 of the 2017 10-K
Minus AROs	0	
Minus Pension / LTSA / Other	0	
Free Cash Flow (in millions)	**$123**	

Exhibit F— Difference in Dynegy's Calculations

Source: Dynegy's 2017 10-K

Note: Calculations are based on year-end 2017 financial results

Difference in Dynegy's MISO Segment Free Cash Flow Calculations		
Other income and expense	26	p. 57 of the 2017 10-K
Mark to market adjustments	-21	p. 57 of the 2017 10-K
Gain on sale of assets	-1	p. 57 of the 2017 10-K
Other	-1	p. 57 of the 2017 10-K
Non-cash compensation expense	1	p. 57 of the 2017 10-K
Non-controlling interests	2	p. 57 of the 2017 10-K
Total (in millions)	**$6**	

Table of Contents

Exhibit G— Impairment of Long-Lived Assets

Description	Judgments and Uncertainties	Effect if Actual Results Differ From Assumptions
Impairment of Long-Lived Assets ASC 360, Property, Plant and Equipment ("PP&E") requires for an entity to assess whether the recorded values of PP&E and finite-lived intangible assets have become impaired when certain indicators of impairment exist. Examples of these indicators include, but are not limited to: • a significant decrease in the market price of a long-lived asset (asset group); • a significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used, or in its physical condition; • a significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset (asset group), including an adverse action or assessment by a regulator; • an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset (asset group); • a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group); and • a current expectation that it is more likely than not a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.	Determining whether an impairment trigger exists involves significant judgment by management which may result in a different answer if our peers were to consider the same facts and circumstances. If it is determined that the asset's value is not recoverable, then we will perform step two of the impairment analysis and fair value the asset using a DCF model and record an impairment charge to reduce the value of the asset to its fair value. The assumptions and estimates used by management to assess whether the asset may have become impaired, whether the asset's value is recoverable, and to determine the fair value of the estimate are significant and may vary materially from the assumptions used by our peers. Examples of the assumptions and estimates used by management include: • determination of increases/decreases in the market price of an asset being a short-term or long-term, fundamental change; • the highest and best use of the asset; • forecasted environmental changes; • forecasted regulatory changes; • management's fundamental view of the long-term pricing environment for energy and capacity; • management's forecast of gross margin, capital expenditures, and operations and maintenance costs; • remaining useful life of our assets; • salvage value; • discount rates; and • inflation rates. The assumptions used in impairment analyses often include unobservable inputs that are based on management's long-term view of our assets remaining useful lives, operating margin and capital requirements.	Changes in market economics and environmental requirements can alter previous assumptions and trigger impairment charges that can materially differ from the results we have reported herein.

Impairments

During the years ended December 31, 2017, 2016 and 2015, we recognized the following impairments in our consolidated statements of operations (amounts in millions).

Facility	Fair Value	2017	2016	2015
Baldwin (1)	$ 97	$ —	$ 645	$ —
Stuart (2)	$ —	—	56	—
Newton FGD (3)	$ —	—	148	—
Killen (4)	$ —	20	—	—
Hennepin (1)	$ 16	10	—	—
Havana (1)	$ 37	89	—	—
Wood River (5)	$ —	—	—	74
Brayton Point (6)	$ 86	—	—	25
Total PP&E Impairments		$ 119	$ 849	$ 99
Inventory	$ —	14	—	—
Equity investment	$ 173	—	9	—
Assets held-for-sale, including $9 of allocated goodwill	$ 176	15	—	—
Total Impairments		$ 148	$ 858	$ 99

(1) Units failed to recover their basic operating costs in the MISO capacity auctions. The impairment was measured using a DCF model. As part of our impairment analysis, we changed the remaining useful lives of certain of our facilities.

(2) We determined that the facility would experience recurring negative cash flows due to on-going required maintenance and environmental capital expenditures, combined with consistently poor reliability. The impairment was measured using a DCF model.

(3) We terminated the flue gas desulfurization ("FGD") systems construction project at our Newton generation facility. The impairment charge was equal to the capitalized cost of the project.

(4) In first quarter 2017, Dayton Power and Light Co., the partner and operator of Killen, announced the shutdown of the Killen generation facility by June 2018. As a result, the DCF model for the facility indicated negative cash flows, resulting in an impairment charge equal to its book value.

(5) Primarily attributable to its uneconomic operation stemming from a poorly designed wholesale capacity market and increased environmental costs. The impairment was measured using a DCF model.

(6) Temperate weather had a significant impact on the facility's remaining cash flows, as the facility retired in May 2017. The impairment was measured using a DCF model.

Brayton Point Retirement

The Brayton Point facility officially retired on June 1, 2017. During the year ended December 31, 2017, we recognized approximately $12 million of severance costs, which were classified within Operating and maintenance expense in our consolidated statement of operations.

Note 9—Joint Ownership of Generating Facilities

We hold ownership interests in certain jointly owned generating facilities. We are entitled to the proportional share of the generating capacity and the output of each unit equal to our ownership interests. We pay our share of capital expenditures, fuel inventory purchases, and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs. Our share of revenues and operating costs of the jointly owned generating facilities is included within the corresponding financial statement line items in our consolidated statements of operations.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	R2018–20
AMENDMENTS TO	)	(Rulemaking – Air)
35 ILL. ADM. CODE 225.233,	)	
MULTI-POLLUTANT STANDARDS (MPS)	)	

CORRECTIONS TO THE PRE-FILED TESTIMONY OF TAMARA DZUBAY ON BEHALF OF ENVIRONMENTAL LAW & POLICY CENTER AND SIERRA CLUB

The Environmental Law & Policy Center and Sierra Club hereby submit the following corrections to the pre-filed testimony of Tamara Dzubay, filed with the Illinois Pollution Control Board on April 3, 2018 in the above-captioned matter.

Page No.	Now Reads	Requested Correction
11	"When an asset is built, the book value is typically calculated through a net present value calculation"	"When an asset is built, the **net** value is typically calculated through a net present value calculation"
11	"When circumstances indicate that the book value of an asset on the balance sheet is less than its fair market value…"	"When circumstances indicate that the book value of an asset on the balance sheet is **more** than its fair market value…"

Exhibit 43
R18-20
4/17/2018
MO

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	R2018–20
AMENDMENTS TO	)	(Rulemaking – Air)
35 ILL. ADM. CODE 225.233,	)	
MULTI-POLLUTANT STANDARDS (MPS)	)	

CERTIFICATE OF SERVICE

The undersigned certifies that a true copy of the foregoing **NOTICE OF FILING** and **CORRECTIONS TO THE PRE-FILED TESTIMONY OF TAMARA DZUBAY ON BEHALF OF ENVIRONMENTAL LAW & POLICY CENTER AND SIERRA CLUB** in R2018-20 were served upon the attached service list by e-mail and by depositing said documents in the United States Mail, postage prepaid, in Chicago, Illinois on April 6, 2018.

Unimuke John Agada
Legal Assistant
Environmental Law & Policy Center
35 E. Wacker Dr., Suite 1600
Chicago, IL 60601
(312) 795-3719

SERVICE LIST:

Marie Tipsord, Hearing Officer
Mark Powell, Senior Attorney
Don Brown, Clerk of the Board
Illinois Pollution Control Board James R.
Thompson Center Suite 11-500
100 W. Randolph Street
312-814-3461
Chicago, Illinois 60601
don.brown@illinois.gov
mark.powell@illinois.Gov
marie.tipsord@illinois.Gov

Eric Lohrenz
Illinois Department of Natural Resources
One Natural Resources Way
Springfield, IL 62702-1271
217-782-1809 (phone)
217-524-9640 (fax)
eric.lohrenz@illinois.gov

Gina Roccaforte
Dana Vetterhoffer
Illinois Environmental Protection Agency
1021 North Grand Avenue East
P.O. Box 19276

Amy C. Antoniolli
Joshua R. More
Ryan Granholm
Schiff Hardin LLP
233 S. Wacker Drive

Springfield, IL 62794-9276
217-782-5544 (phone)
217-782-9807 (fax)
gina.roccaforte@illinois.gov
dana.vetterhoffer@illinois.gov

Suite 6600
Chicago, IL 60606
312-258-5769
aantoniolli@schiffhardin.com
jmore@schiffhardin.com
rgranholm@schiffhardin.com

Andrew Armstrong
Office of the Attorney General
500 South Second Street
Springfield, IL 62706
217-782-9031 (phone)
217-524-7740 (fax)
aarmstrong@atg.state.il.us

Greg Wannier
Staff Attorney
Sierra Club
2101 Webster St., Suite 1300
Oakland CA 94612
greg.wannier@sierraclub.org

James Gignac
Matthew J. Dunn
Stephen Sylvester
Office of the Attorney General
69 West Washington Street, Suite 1800
Chicago, IL 60602
312-814-2634 (phone)
312-814-2347 (fax)
jgignac@atg.state.il.us
mdunn@atg.state.il.us
ssylvester@atg.state.il.us

Faith Bugel
Attorney at Law
1004 Mohawk
Wilmette, IL 60091
fbugel@gmail.com

Katy Khayyat
Department of Commerce & Economic Opportunity
Small Business Office
500 East Monroe Street
217-785-6162 (phone)
Springfield, IL 62701
katy.khayyat@illinois.gov

Katherine D. Hodge
HelperBroom LLC
4340 Acer Grove Drive
500 East Monroe Street
Springfield, IL 62711
217-523-4900 (phone)
217-523-4948 (fax)
khodge@heplerbroom.com

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	
AMENDMENTS TO	)	**R18-20**
35 ILL. ADM. CODE 225.233,	)	**(Rulemaking – Air)**
MULTI-POLLUTANT STANDARDS (MPS)	)	

NOTICE OF FILING

To: ALL PARTIES ON THE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today electronically filed with the Office of the Clerk of the Illinois Pollution Control Board the attached **PREFILED QUESTIONS FOR TAMARA DZUBAY**, copies of which are herewith served upon you.

/s/ Ryan Granholm
Ryan Granholm

Dated: April 10, 2018

Ryan Granholm
SCHIFF HARDIN LLP
233 South Wacker Drive
Suite 7100
Chicago, Illinois 60606
312-258-5500

Exhibit 44
R18-20
4/17/2018
MA

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	
AMENDMENTS TO	)	**R18-20**
35 ILL. ADM. CODE 225.233,	)	**(Rulemaking – Air)**
MULTI-POLLUTANT STANDARDS (MPS)	)	

PREFILED QUESTIONS FOR TAMARA DZUBAY

NOW COME Dynegy Midwest Generation, LLC, Illinois Power Generating Company, Illinois Power Resources Generating, LLC and Electric Energy, Inc. (collectively, "the Companies"), by their attorneys, Schiff Hardin LLP, and hereby submit prefiled questions for Tamara Dzubay. The Companies request that the Hearing Officer allow follow-up questioning to be asked at hearing based on the answers provided.

1. Have you ever been found to be an expert by any court of law?
2. Have you ever given testimony before a legislative body before?
3. Do you disagree with The Companies' assertions that the MPS can, at times, cause them to operate certain units below their marginal operating costs?

Respectfully submitted,

/s/ Ryan Granholm
Attorney for The Companies

Dated: April 10, 2018

SCHIFF HARDIN LLP
Josh More
Amy Antoniolli
Ryan Granholm
Caitlin Ajax
233 South Wacker Drive, Suite 7100
Chicago, Illinois 60606
(312) 258-5500

CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 10th day of April, 2018, I have electronically served the attached **PREFILED QUESTIONS FOR TAMARA DZUBAY**, upon all parties on the attached service list.

My e-mail address is rgranholm@schiffhardin.com;

The number of pages in the e-mail transmission is 4.

The e-mail transmission took place before 5:00 p.m.

/s/ Ryan Granholm
Ryan Granholm

Joshua More
Amy Antoniolli
Ryan Granholm
Caitlin Ajax
SCHIFF HARDIN LLP
233 South Wacker Drive
Suite 7100
Chicago, Illinois 60606
312-258-5500

SERVICE LIST	
Don Brown, Assistant Clerk Don.brown@illinois.gov Mark Powell, Hearing Officer Mark.Powell@illinois.gov Marie Tipsord, Hearing Officer Marie.Tipsord@illinois.gov Illinois Pollution Control Board James R. Thompson Center Suite 11-500 100 West Randolph Chicago, Illinois 60601	Antonette Palumbo Antonette.palumbo@illinois.gov Dana Vetterhoffer Dana.vetterhoffer@illinois.gov Gina Roccaforte Gina.roccaforte@illinois.gov Division of Legal Counsel Illinois Environmental Protection Agency 1021 North Grand Avenue, East P.O. Box 19276 Springfield, Illinois 62794-9276
Eric Lohrenz Eric.lohrenz@illinois.gov Office of General Counsel Illinois Department of Natural Resources One Natural Resources Way Springfield IL 62702-1271	Katy Khayat Katy.Khayyat@illinois.gov Department of Commerce and Economic Opportunity Small Business Office 500 East Monroe Street Springfield, IL 62701
Stephen Sylvester ssylvester@atg.state.il.us 69 West Washington Street, Suite 1800 Chicago, IL 60602 Andrew Armstrong aarmstrong@atg.state.il.us 500 South Second Street Springfield, IL 62706	Greg Wannier, Staff Attorney Greg.wannier@sierraclub.org Sierra Club Environmental Law Program 2101 Webster Street, Suite 3100 Oakland, CA 94612
Jean-Luc Kreitner jkreitner@elpc.org Justin Vickers jvickers@elpc.org 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	Katherine D. Hodge HeplerBroom LLC khodge@heplerbroom.com 4340 Acer Grove Drive Springfield, IL 62711
Faith Bugel fbugel@gmail.com 1004 Mohawk Wilmette, IL 60091	

R18-20

Questions for ELPC & Sierra Club Witness Tamara Dzubay

1. Aside from attachments to your testimony that outside parties prepared (e.g., parts of Dynegy financial statements), who prepared each attachment? Did you review all of the attachments to your testimony in their entirety?

2. On page 10 of your testimony, you state that, "While the cash flow position of the [MISO] segment is an important financial indicator," that segment is "not cash flow negative." What relevance should the Board place on whether (or not) the regulated entity is cash flow negative or positive? Please cite the relevant section(s) of the Act.

IT IS SO ORDERED.

Marie E Tipsord

Marie E. Tipsord
Hearing Officer
Illinois Pollution Control Board
100 West Randolph, Suite 11-500
Chicago, Illinois 60601
(312) 814-4925
Marie.Tipsord@illinois.gov

Exhibit 45
R18-20
4/17/2018
MT

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	
AMENDMENTS TO	)	**R18-20**
35 ILL. ADM. CODE 225.233,	)	**(Rulemaking – Air)**
MULTI-POLLUTANT STANDARDS (MPS)	)	

NOTICE OF FILING

To: ALL PARTIES ON THE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today electronically filed with the Office of the Clerk of the Illinois Pollution Control Board the attached **PREFILED QUESTIONS FOR THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY**, copies of which are herewith served upon you.

/s/ Ryan Granholm
Ryan Granholm

Dated: April 10, 2018

Ryan Granholm
SCHIFF HARDIN LLP
233 South Wacker Drive
Suite 7100
Chicago, Illinois 60606
312-258-5500

Exhibit 46
R18-20
4/17/2018
MT

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of:	)	
	)	
AMENDMENTS TO	)	**R18-20**
35 ILL. ADM. CODE 225.233,	)	**(Rulemaking – Air)**
MULTI-POLLUTANT STANDARDS (MPS)	)	

PREFILED QUESTIONS FOR THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

NOW COME Dynegy Midwest Generation, LLC, Illinois Power Generating Company, Illinois Power Resources Generating, LLC and Electric Energy, Inc. (collectively, "The Companies"), by their attorneys, Schiff Hardin LLP, and hereby submit prefiled questions for the Illinois Environmental Protection Agencies. The Companies request that the Hearing Officer allow follow-up questioning to be asked at hearing based on the answers provided.

1. Please describe the Illinois Environmental Protection Agency's ("Agency" or "IEPA") experience with Clean Air Act Section 110(l) "anti-backsliding" analyses.
    a. Can you provide recent examples of such analyses?
    b. What method of analysis has the Agency used?
2. Has the Agency ever used actual emissions in connection with Section 110(l) "anti-backsliding" analyses? If so, please identify the instances.
3. Does the Agency agree with the Illinois Attorney General's ("AGO") reliance on actual instead of allowable emissions for evaluating the environmental impacts of IEPA's proposal and analysis of the proposal under Section 110(l), as set forth in the AGO's April 3, 2018 pre-filed testimony? If not, why not?
4. Has the Agency discussed with the United States Environmental Protection Agency ("USEPA") the assertion on p. 5 of the AGO's April 3, 2018 pre-filed testimony that Section 110(l) "anti-backsliding" analysis "requires consideration of . . . 'actual,' not allowable, emissions"? If so, what did the USEPA say?
5. Has the AGO presented any evidence demonstrating to the IEPA that the proposed annual emissions caps of 49,000 tons for SO_2 and 25,000 tons for NO_X are not approvable by USEPA?

6. Has the AGO presented any evidence demonstrating to the IEPA that the proposed annual emissions caps of 49,000 tons for SO_2 and 25,000 tons for NO_X will cause or threaten nonattainment of any National Ambient Air Quality Standard ("NAAQS")?

7. Has the AGO presented any evidence demonstrating to the IEPA that an SO_2 emissions cap lower than 49,000 tons is necessary for the proposed MPS revisions to be as protective of human health and the environment as the current MPS?

   a. Has the AGO presented any evidence demonstrating to the IEPA that an SO_2 emissions cap lower than 34,094 tons is necessary for the proposed MPS revisions to be as protective as the current MPS?

   b. Has the AGO presented any evidence demonstrating to the IEPA that the proposed annual SO_2 emissions cap must decrease when MPS units retire in order for the proposed MPS revisions to be as protective as the current MPS?

8. Has the AGO presented any evidence demonstrating to the IEPA that a NO_X emissions cap lower than 25,000 tons is necessary for the proposal to be as protective of human health and the environment as the current MPS?

   a. Has the AGO presented any evidence demonstrating to the IEPA that n NO_X emissions cap lower than 18,920 tons is necessary for the proposal to be as protective of human health and the environment as the current MPS?

   b. Has the AGO presented any evidence demonstrating to the IEPA that the proposed annual NO_X emissions cap must decrease when MPS units retire in order for the proposed MPS revisions to be as protective as the current MPS?

9. Has the AGO provided a projection of what the heat input for any MPS unit will be in the future?

10. Under the current MPS could the MPS fleet emit more than 34,094 tons of SO_2 in a year and remain in compliance?

11. Under the current MPS could the MPS fleet emit more than 18,920 tons of NO_X in a year and remain in compliance?

12. Does Tamara Dzubay's testimony regarding Dynegy's financial situation change the Agency's evaluation of or support for this proposal?

13. Does the Agency believe that Vistra's participation in this rulemaking is necessary for the Agency to present sufficient evidence to support its proposal?

CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 2nd day of March, 2018, I have electronically served the attached **PREFILED QUESTIONS FOR THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY**, upon all parties on the attached service list.

My e-mail address is rgranholm@schiffhardin.com;

The number of pages in the e-mail transmission is 5.

The e-mail transmission took place before 5:00 p.m.

/s/ Ryan Granholm
Ryan Granholm

Joshua More
Amy Antoniolli
Ryan Granholm
Caitlin Ajax
SCHIFF HARDIN LLP
233 South Wacker Drive
Suite 7100
Chicago, Illinois 60606
312-258-5500

SERVICE LIST	
Don Brown, Assistant Clerk Don.brown@illinois.gov Mark Powell, Hearing Officer Mark.Powell@illinois.gov Marie Tipsord, Hearing Officer Marie.Tipsord@illinois.gov Illinois Pollution Control Board James R. Thompson Center Suite 11-500 100 West Randolph Chicago, Illinois 60601	Antonette Palumbo Antonette.palumbo@illinois.gov Dana Vetterhoffer Dana.vetterhoffer@illinois.gov Gina Roccaforte Gina.roccaforte@illinois.gov Division of Legal Counsel Illinois Environmental Protection Agency 1021 North Grand Avenue, East P.O. Box 19276 Springfield, Illinois 62794-9276
Eric Lohrenz Eric.lohrenz@illinois.gov Office of General Counsel Illinois Department of Natural Resources One Natural Resources Way Springfield IL 62702-1271	Andrew Armstrong aarmstrong@atg.state.il.us Office of the Attorney General 500 South Second Street Springfield, IL 62706
James Gignac jgignac@atg.state.il.us Stephen Sylvester, Assistant Attorney General ssylvester@atg.state.il.us Matthew Dunn mdunn@atg.state.il.us 69 West Washington Street, Suite 1800 Chicago, IL 60602 enviro@atg.state.il.us	Katy Khayat Katy.Khayyat@illinois.gov Department of Commerce and Economic Opportunity Small Business Office 500 East Monroe Street Springfield, IL 62701
Jean-Luc Kreitner jkreitner@elpc.org Justin Vickers jvickers@elpc.org 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	Greg Wannier, Staff Attorney Greg.wannier@sierraclub.org Sierra Club Environmental Law Program 2101 Webster Street, Suite 3100 Oakland, CA 94612
Faith Bugel fbugel@gmail.com Interested Party 1004 Mohawk Wilmette, IL 60091	Katherine D. Hodge HeplerBroom LLC khodge@heplerbroom.com 4340 Acer Grove Drive Springfield, IL 62711

Susmita and Doug,

Thanks for talking to us on Thursday. As we mentioned, here are some questions and the citations to cases mentioned by the Illinois Attorney General's Office in their prefiled testimony. FYI, our hearing is Tuesday the 17th, so if there is any way you can respond to us by the end of the week, we'd really appreciate it.

1) Do you agree with the statement, "the United States Environmental Protection Agency ("USEPA") has consistently taken the position that an 'anti-backsliding' analysis under Section 110(l) requires consideration of a proposed SIP amendment's impact on 'actual,' not allowable, emissions."?

   The U.S. EPA does not agree with that statement.

2) If this statement is incorrect, can you explain how it's incorrect?

   The statement is incorrect in that U.S. EPA typically requires a comparison of allowable emissions under the currently approved state implementation plan (SIP) to the allowable emissions under the SIP revision under consideration for approval.

3) What does USEPA normally require for a 110(l) demonstration in terms of comparison of emissions?

   Normally, for a 110(l) demonstration a comparison of allowable emissions under the currently approved (aka "existing SIP") to the allowable emissions under the SIP revision being considered is made. If the allowable emissions under the revised SIP are no greater than the allowable emissions under the existing SIP (i.e. the SIP is not being made less stringent), 110(l) is satisfied. If the allowable emissions under the revised SIP are higher under the allowable emissions under the existing SIP (i.e. the SIP is being relaxed), an additional demonstration would be needed to show that attainment, maintenance, or progress towards meeting air quality standards are not interfered with before the SIP revision could be approved.

4) Is an allowable-to-allowable comparison required for the Illinois EPA's 110(l) demonstration for the amendments being proposed to the MPS rule?

   Yes. In general, an allowable-to-allowable comparison is required for every SIP revision and is the basis for demonstrating that 110(l) is satisfied or whether a more in-depth 110(l) demonstration is needed, as is the case of relaxations of SIPs. See response to Question 3 above.

5) In your experience, how often has USEPA required an actuals-to-actuals comparison instead of an allowables-to-allowables comparison?

   Never. An "actuals-to-actuals" comparison is impossible because "actuals" can only be measured after they have happened. You cannot predict what the future actual emissions

Exhibit 47
R18-20
4/17/18

from a source will be. The best you can do is place an upper limit (i.e. an allowable limit) that sources are required to emit below. SIP-approved limits are allowable limits that sources, when in compliance, operate up to but typically operate well below.

Citations:

II. THE BOARD SHOULD CONSIDER THE IMPACT ILLINOIS EPA'S AMENDMENTS WOULD HAVE ON ACTUAL EMISSIONS.

…

Moreover, though, Illinois EPA's interpretation of Section 110(l) of the Clean Air Act is inconsistent with USEPA's. Illinois EPA asserts that "the methodology used by the Agency to calculate **allowable** emissions was chosen because it is the method the State is required to use to demonstrate that this SIP revision is approvable by USEPA." IEPA Responses and Information Requested from the January Hearings (Feb. 16, 2018), at 2 n.1 (emphasis added). USEPA, though, has long taken the position that the appropriate inquiry when conducting an "anti-backsliding" analysis pursuant to Section 110(l) is whether "**actual**" emissions, not allowable emissions, will increase. *See, e.g., Kentucky Resources Council, Inc. v. EPA*, 467 F.3d 986, 995 (6th Cir. 2006) ("As long as **actual** emissions in the air are not increased, EPA believes that equivalent (or greater) emissions reductions will be acceptable to demonstrate non-interference.") (quoting 70 Fed. Reg. 28429, 28430 (May 15, 2005)) (emphasis added); USEPA, *Approval and Revision of Air Plans; Arizona; Regional Haze State and Federal Implementation Plans; Reconsideration*, 83 Fed. Reg. 15139, 15149 (Mar. 27, 2017) (cited by Dynegy to Illinois EPA on page 3 of memorandum attached as Attachment 9 to IEPA Responses to Pre-Filed Questions (Jan. 12, 2018)).

…

Analyzing proposed amendments to a rule regulating specifically coal-fired power plants based solely on "allowable" emissions would paint a particularly distorted picture of those amendments' environmental impact. As USEPA maintained to the Seventh Circuit Court of Appeals in 2014, it was USEPA's "long-standing practice and EPA policy" to use actual emissions data for coal-fired power plants "when demonstrating permanent and enforceable emission reductions." *Sierra Club v. USEPA*, 774 F.3d 383, 396 (7th Cir. 2014) (quoting USEPA brief).6 USEPA implemented this policy because "assuming that all sources would be operating at maximum capacity at once would result in a gross overestimation of levels." *Id.* The Seventh Circuit concurred with USEPA's approach: "[USEPA] has articulated a rational basis for its conclusion . . . that using maximum allowable emissions levels for power plants would have been unrealistic." *Id.* at 397.

EPA disagrees that the citations in the highlighted language demonstrate that EPA has "long taken the position" that a comparison of actual emissions, rather than allowable emissions, is appropriate for a section 110(l) analysis. The Federal Register notice quoted in the Kentucky Resources Council case was part of an explanation that the use of substitute control measures to demonstrate noninterference under section 110(l) can be done prior to a complete attainment demonstration, provided the status quo air quality is preserved. Thus, the reference to "actual" emissions was not in the context of "actuals vs. allowables," but rather a reference to the status of the air quality. Further, the 2014 Sierra Club case is not relevant to a section 110(l) analysis because it addressed a different evaluation. This case involved a challenge to EPA's redesignation of certain areas, and the court was addressing EPA's assessment of whether improvement in air quality was due to permanent and enforceable emissions reductions for purposes of redesignation, not as part of a determination under section 110(l) that a SIP revision will not result in interference with attainment or maintenance of the NAAQS in the future.

Roccaforte, Gina

From: Aburano, Douglas <aburano.douglas@epa.gov>
Sent: Thursday, April 12, 2018 3:12 PM
To: Bloomberg, David E.; Dubey, Susmita
Cc: Vetterhoffer, Dana
Subject: [External] RE: 110(l) Demonstrations
Attachments: IEPA 110L Questions Final.docx; IEPA 110L Questions Final.pdf

For your convenience, here are both a Word and PDF version of our response in case one format is preferred over another.

From: Aburano, Douglas
Sent: Thursday, April 12, 2018 2:37 PM
To: 'Bloomberg, David E.' <David.Bloomberg@Illinois.gov>; Dubey, Susmita <dubey.susmita@epa.gov>
Cc: Vetterhoffer, Dana <Dana.Vetterhoffer@Illinois.gov>
Subject: RE: 110(l) Demonstrations

David and Dana,

Attached are EPA's responses to your questions. Our answers and additions are in red for easy identification. Please let us know if you have any questions regarding the attached.

Thanks,

Doug

From: Bloomberg, David E. [mailto:David.Bloomberg@Illinois.gov]
Sent: Monday, April 09, 2018 11:44 AM
To: Aburano, Douglas <aburano.douglas@epa.gov>; Dubey, Susmita <dubey.susmita@epa.gov>
Cc: Vetterhoffer, Dana <Dana.Vetterhoffer@Illinois.gov>
Subject: 110(l) Demonstrations

Susmita and Doug,

Thanks for talking to us on Thursday. As we mentioned, here are some questions and the citations to cases mentioned by the Illinois Attorney General's Office in their prefiled testimony. FYI, our hearing is Tuesday the 17th, so if there is any way you can respond to us by the end of the week, we'd really appreciate it.

1) Do you agree with the statement, "the United States Environmental Protection Agency ("USEPA") has consistently taken the position that an 'anti-backsliding' analysis under Section 110(l) requires consideration of a proposed SIP amendment's impact on 'actual,' not allowable, emissions."?

2) If this statement is incorrect, can you explain how it's incorrect?

3) What does USEPA normally require for a 110(l) demonstration in terms of comparison of emissions?

4) Is an allowable-to-allowable comparison required for the Illinois EPA's 110(l) demonstration for the amendments being proposed to the MPS rule?

5) In your experience, how often has USEPA required an actuals-to-actuals comparison instead of an allowables-to-allowables comparison?

Citations:

II. THE BOARD SHOULD CONSIDER THE IMPACT ILLINOIS EPA'S AMENDMENTS WOULD HAVE ON ACTUAL EMISSIONS.

...

Moreover, though, Illinois EPA's interpretation of Section 110(l) of the Clean Air Act is inconsistent with USEPA's. Illinois EPA asserts that "the methodology used by the Agency to calculate **allowable** emissions was chosen because it is the method the State is required to use to demonstrate that this SIP revision is approvable by USEPA." IEPA Responses and Information Requested from the January Hearings (Feb. 16, 2018), at 2 n.1 (emphasis added). USEPA, though, has long taken the position that the appropriate inquiry when conducting an "anti-backsliding" analysis pursuant to Section 110(l) is whether "**actual**" emissions, not allowable emissions, will increase. *See, e.g., Kentucky Resources Council, Inc. v. EPA*, 467 F.3d 986, 995 (6th Cir. 2006) ("As long as **actual** emissions in the air are not increased, EPA believes that equivalent (or greater) emissions reductions will be acceptable to demonstrate non-interference.") (quoting 70 Fed. Reg. 28429, 28430 (May 15, 2005)) (emphasis added); USEPA, *Approval and Revision of Air Plans; Arizona; Regional Haze State and Federal Implementation Plans; Reconsideration*, 83 Fed. Reg. 15139, 15149 (Mar. 27, 2017) (cited by Dynegy to Illinois EPA on page 3 of memorandum attached as Attachment 9 to IEPA Responses to Pre-Filed Questions (Jan. 12, 2018)).

...

Analyzing proposed amendments to a rule regulating specifically coal-fired power plants based solely on "allowable" emissions would paint a particularly distorted picture of those amendments' environmental impact. As USEPA maintained to the Seventh Circuit Court of Appeals in 2014, it was USEPA's "long-standing practice and EPA policy" to use actual emissions data for coal-fired power plants "when demonstrating permanent and enforceable emission reductions." *Sierra Club v. USEPA*, 774 F.3d 383, 396 (7th Cir. 2014) (quoting USEPA brief).6 USEPA implemented this policy because "assuming that all sources would be operating at maximum capacity at once would result in a gross overestimation of levels." *Id.* The Seventh Circuit concurred with USEPA's approach: "[USEPA] has articulated a rational basis for its conclusion . . . that using maximum allowable emissions levels for power plants would have been unrealistic." *Id.* at 397.